State of California

Department of Water Resources

DRAFT

Determination of Revenue Requirements

To Be Submitted To
The California Public Utilities Commission
Pursuant To The California Water Code Sections 80110 And 80134

October 19, 2001

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A. PURPOSE OF FILING

Pursuant to California Water Code sections 80110 and 80134, the California Department of Water Resources (the "Department") hereby advises and notifies the California Public Utilities Commission (the "Commission") of the Department's revenue requirements for the period January 17, 2001, through and including December 31, 2002 (the "Revenue Requirement Period"). The Department understands that the Commission is establishing rates for Department furnished power under Commission Application 00-11-038 et al. – Allocation of California Department of Water Resources Revenue Requirement.

The Department has prepared this revenue requirement advice and notification to reflect various changes since its August 7, 2001 filing with the Commission. In summary, these changes include:

1. Changes to the load forecast to reflect the increase in direct access loads resulting from an extension by the Commission of the cut off date for retail end-users to enter into contracts with alternative electric service providers (referenced to herein as "direct access");
2. Changes to the Department's financing requirements principally resulting from the Commission's rejection of the proposed rate agreement with the Department and inaction on the adoption of a rate order for the Department;
3. Changes to the assumptions regarding future natural gas prices;
4. Changes to the load forecast to reflect the effects of only the 20/20 Program for the year 2001 and those demand-side management ("DSM") and conservation related activities which have been authorized by legislation;
5. Changes to the amount of power under long-term Department contracts;
6. Changes to the methodology for calculating ancillary service costs;
7. Changes in the estimated prices received by the Department for sales of its contracted power to wholesale power purchasers ("off-system" sales); and
8. Certain changes in the timing of the receipt of revenues by the Department.

This update provides the Commission with the Department's determination of the total revenue requirement for the Department's purchase of net short energy (as defined hereinafter). During the Revenue Requirement Period, the Department is acquiring on behalf of the end users within the retail service areas of Pacific Gas and Electric Company ("PG&E"), Southern California Edison Company ("SCE"), and San Diego Gas and Electric Company ("SDG&E") (the "Customers"), the difference between their total Customer load requirements and the electricity supplied by power supply resources still owned by, or under contract to PG&E, SCE, and SDG&E (the IOUs'). This difference is the "net short" requirement. The Department is also acquiring, through the ISO's ancillary services market, the electric energy and capacity required for grid reliability in the IOU's service areas, to the extent these services are not otherwise provided by the IOUs through their retained generation, as described more fully hereinafter.

This updated revenue requirement includes additional explanation of the assumptions and methods for determining the revenue requirement, summarizing much of what has been discussed in two transcribed public workshops held on July 27, 2001 and October 5, 2001. This filing provides additional description of the circumstances in the power supply market earlier this year when the Department began procuring the net short requirements of the Customers to put in context the energy procurement effort. The filing also provides description supporting the Department's forecast that the market will continue to be relatively stable as a result of, among other things, the Department's procurement strategies.

The Department will conduct a public workshop on Monday, October 22, 2001, from 1:00 PM to 5:00 PM, in the Central Valley conference room at 1001 I Street, Sacramento, California, to respond to requests for clarification of the updated revenue requirement and to receive comments on the underlying assumptions and resulting projections. Comments on this filing must be submitted in writing to the Department by October 26, 2001. To the extent any comments or information provided to the Department as a result of the workshop, and any written comments provided by October 26, 2001, result in a decision by the Department to modify its revenue requirement determination further, such modifications will be communicated to the Commission and incorporated into the record of the Commission in its consideration of rates and/or charges to implement the Department's revenue requirement. The Department plans to file its revenue requirement with the Commission on or about November 2, 2001. Any questions regarding the Commission's plans for its process for implementation of the Department's revenue requirement should be forwarded to the Commission.

B. SUMMARY OF REVENUE REQUIREMENTS

In summary, the Department's revenue requirements as determined in this filing consist of the following elements:

1. Costs associated with power supply to be delivered to the Department under existing long-term power purchase contracts;
2. Costs associated with the Department's acquisition of power to meet the difference between the net short and the power available under the Department's long-term contracts and DSM programs undertaken by the Department (the "residual net short");
3. Costs associated with the Department's financing activities, including debt service;
4. Financing and operating reserves as determined by the Department;
5. Administrative and general expenses;
6. DSM expenses;
7. Costs associated with ISO grid reliability purchases; and
8. Cash flow impacts associated with leads and lags in payment for energy and services acquired and provided.

Over the Revenue Requirement Period, the Department is projected to incur:

- $98.8 million in administrative and general expenses;
- $313.8 million in DSM related costs;
- $5.4 billion in contract power costs to cover the net short requirement of the Customers;
- $9.5 billion in costs to cover the Customers' residual net short requirements; and
- $787.1 million to acquire ancillary services and associated energy not otherwise provided by the IOUs from their retained generation

On a cash basis (i.e., including the cash effect of leads and lags), the Department's revenue requirements represent an aggregate total expenditure of about $16.0 billion. Combined with financing costs (including principal payments) of about $1.2 billion, the Department's expenditures for the Revenue Requirement Period are expected to total $17.2 billion. Of that amount, approximately $200 million is expected to be funded from revenues from off-system sales, with the remaining $6.8 billion expected to be paid during the Revenue Requirement Period. These amounts, combined with amounts previously advanced from the State's General Fund and interim financing proceeds, result in a Customer revenue requirement of $10.2 billion. Table 1 presents the incurred and expected revenue requirements by quarter for the Revenue Requirement Period. This revenue requirement projection is based upon the repayment and coverage requirements of the interim financing agreements that do not permit the Department to assume the benefit of the expected future long-term bond issue.

TABLE 1
SUMMARY OF THE DEPARTMENT'S REVENUE REQUIREMENTS[1,2]
(MILLIONS OF DOLLARS)

Quarter	Retail Sales (GWh)	A&G	DSM	Contract Power	Residual Net Short	Ancillary Services	Subtotal	Lead (Lag) Accrual to Cash	Total Operating Expenditures	Interim Loan Costs	Total Expenditures	Customer Revenue Requirements
Q1 2001	12,359.5	$ 7.8	$ 0.5	$ --	$3,581.5	$ 258.1	$ 3,847.4	$(1,505.2)	$ 2,342.3	$ (7.7)	$ 2,334.5	$ 770.9
Q2 2001	19,620.0	10.2	225.8	627.9	3,884.2	208.8	4,731.6	(144.2)	4,587.4	(39.3)	4,548.0	2,038.7
Q3 2001	16,053.9	11.3	87.5	925.7	1,140.9	51.3	2,358.9	81.9	2,440.7	(49.3)	2,391.4	1,661.6
Q4 2001	10,915.7	9.0	--	708.9	231.5	55.9	1,097.1	442.5	1,539.6	(42.1)	1,497.5	1,211.4
Q1 2002	9,313.1	15.1	--	663.8	169.8	51.6	904.0	1043.0	1,947.0	(14.2)	1,932.8	1,038.2
Q2 2002	7,957.1	15.1	--	680.5	129.8	42.7	871.4	(20.2)	851.2	434.1	1,285.4	890.1
Q3 2002	12,311.9	15.1	--	959.0	220.2	64.1	1,263.4	(25.0)	1,238.4	435.9	1,674.3	1,373.0
Q4 2002	10,812.3	15.1	--	844.5	164.4	54.8	1,083.1	20.4	1,103.4	436.3	1,539.7	1,205.8
Total	99,353.5	$ 98.8	$313.8	$5,410.4	$9,522.2	$ 787.1	$16,156.7	$ (106.8)	$ 16,049.9	$1,153.6	$17,203.6	$10,189.8

[1] Totals may not add due to rounding.
[2] Preliminary and subject to change.

In contrast, the Department's filing dated August 7, 2001 for the same Revenue Requirement Period indicated an expected total expenditure of $21.45 billion and a Customer revenue requirement of $12.6 billion. The change from the August 7, 2001 filing, therefore, is a decrease in total operating expenditures of $4.8 billion and a decrease in Customer revenue requirement of about $2.4 billion. As described in greater detail in Section F of this filing, these changes represent the cumulative effect of the following factors:

1. Reductions in future energy deliveries by the Department due to increased participation in direct access by electric end-users. This increase in direct access participation is the result of the Commission's decision to extend the cutoff date for contracting with alternative electricity providers from the originally planned July 1, 2001 date to the Commission's September 20, 2001 date;
2. Increases in the Department's financing obligations resulting from its inability to issue long-term debt due to the rejection by the Commission of the proposed rate agreement, the absence of a Commission rate order, and the corresponding need to comply with the term-out, coverage, interest rate step-up, and other provisions of the Department's interim borrowing;
3. Changes in the assumptions relating to, and reductions in, the projected cost of fuel resulting from increased supply and deliverability of natural gas resources in California;
4. Increases in the Department's load forecast resulting from the elimination of certain DSM programs the Department had previously assumed would be undertaken during 2002;
5. Changes in the Department's projection of contract purchases due to changes in the number and type of power supply contracts expected to be in place during 2002, along with changes in the amount of energy dispatched under those contracts based upon changes in regional fuel prices; and

6. Changes in the methodology for calculating ancillary service costs to reflect recent historical market conditions.

C. BACKGROUND

The Department plays a pivotal and evolving role in the California electricity marketplace. Its role began in December 2000, when the ISO requested the Department, in its capacity as operator of the State Water Project, to assist in avoiding rolling blackouts by purchasing power in the spot market and delivering it to the ISO for redelivery to the Customers. Several such purchases and deliveries occurred, totaling approximately 68,000 MWh and $39 million.

On January 17, 2001, the Governor of the State of California issued an Executive Order directing the Department to acquire electric energy supplies to assist in mitigating the effects of the energy supply emergency. In conjunction with this Executive Order, approximately $440 million of the Department's general fund appropriations, originally intended for other purposes, were made available to the Department to fund energy purchases. Of this total, approximately $302 million was expended for energy purchases. Senate Bill 7 from the First Extraordinary Session of 2001 ("SB 7X"), the first urgency legislation to confirm the Department's responsibilities in the emergency, was passed and signed into law on January 19, 2001, and appropriated an additional $400 million to the Department for power purchases.

On February 1, Assembly Bill 1 from the First Extraordinary Session of 2001 ("the Act") was enacted into law. The Act authorized the Department to purchase the net short energy requirements of the Customers. The Act included a direct appropriation of an additional $500 million for that purpose, and created a process whereby the Department could request and receive additional "deficiency appropriations" upon 10 days advance written notification to the Legislature. The Act grants certain powers to, and establishes certain requirements of, the Department in connection with its role as an energy provider. These powers and requirements include, but are not limited to, the following:

- Authorizes the Department to act on behalf of the State of California to secure necessary power supplies for resale to the Customers;
- Requires the Department to retain title to all power sold, but allows it to enter into service agreements with the IOUs for distribution and billing services;
- Authorizes the Department and the Commission to enter into an agreement with respect to charges for power sold or otherwise made available by the Department, which agreement shall have the full force and effect of a "financing order" by the Commission;
- Authorizes and entitles the Department to collect all revenue requirements incurred in connection with its activities under the Act, including debt service costs and related debt service coverage requirements, payments under power purchase contracts, spot market purchase costs, reserves as determined by the Department, and administrative costs, among others, through Customer charges;

- Establishes that the payment for power delivered by the Department is a direct obligation of the Customers; and
- Prohibits the Department from entering into new power purchase agreements on or after January 1, 2003, but allows it to continue administering existing contracts and enforcing revenue requirements beyond that date.

The Department began its power procurement program immediately upon the signing of the Executive Order. From January 17 through late February 2001, the Department's power purchase program involved solely the purchase of energy through the spot markets. By March 2001, the Department had begun to rely on a portfolio of bilateral contracts, funded conservation, and spot market purchases to meet the net short requirements of the Customers.

On January 22, the Department issued a competitive request for bids for firm energy supply, with bids due on January 23, 2001. Those bids established a benchmark of the willingness of suppliers to enter into various term bilateral contracts at an average long-term cost of $69 per megawatt-hour ("MWh"), compared to the then-current average daily price of approximately $450 per MHW. On January 30, the Department released a more comprehensive request for bids for power supply due on February 6, 2001. Based upon both of these requests for bids and subsequent unsolicited proposals, the Department entered into long-term contracts for power supply with 25 separate power suppliers with a total of 54 separate power supply transactions (not including the Power Exchange ("PX") block forward contracts obtained by the State.

The amounts of purchases under long-term contracts were minor until April 2001. Volumes under long-term contract and short-term contracts of several weeks to 90 days increased significantly in June 2001 to provide price stability during the summer peak period. Conservation programs funded by the Department commenced in June 2001.

Overall, the activities which have been initiated by the Department since enactment of the Act include the following:

- Forecasting the electrical needs of the IOUs and the net short requirements of the Customers;
- Entering into contracts for firm, unit contingent, and dispatchable power supplies to meet a portion of the Customers' net short requirements;
- Managing the scheduling of available power supply resources to maximize the economic value of the Department's power supply program;
- Developing programs to increase the availability of cost effective interruptible load control, securing needed generating reserve capacity, and mitigating the risk of future natural gas price and supply volatility;
- Securing needed generating reserve capacity; and
- Mitigating the risk of future natural gas price and supply volatility.

The above actions of the Department have achieved the following benefits, among others, for the Customers by establishing a creditworthy purchaser and creating a portfolio of long-term, short-term, and spot market purchases to meet the net short energy requirements:

- Prices have dropped dramatically and stabilized. The average daily price of net short energy has fallen from a daily average price of over $450 per MWh in January 2001 to less than $100 per MWh in October 2001. Daily net short energy purchase costs have fallen from as high as $100 million per day to less than $15 million per day. Contracts and conservation have reduced spot and forward market prices. Even before the June 19, 2001 Federal Energy Regulatory Commission ("FERC") market mitigation order establishing soft price caps, average daily spot market prices had dropped to below $100 per MWh even during 100ºF+ weather, compared to the May 2001 average spot price of over $270 per MWh, due in large part to the combination of conservation and the Department's contracts. Spot prices have since stabilized at prices averaging approximately $35 per MWh as of October 2001, about one-tenth of the spot market prices in January and February when virtually all net short energy purchases were made in the short-term market. The Department's power supply contracts have enabled prices in the market to respond to normal market influences by assuring enough supply under firm or formulaic prices.
- The system has become more reliable. There has not been a blackout in California since May 8, 2001, despite predictions earlier this year by market observers, including the staff of the Western Systems Coordinating Council (the "WSCC"), of over 300 hours of blackouts for this summer. Over 50 percent, on a capacity basis, of the Department's contracts during summer 2002 provide for new generation assets to supply power to the market. This contract certainty has increased the near-term and future additions of generation resources to meet California's power supply needs. The financial assurance from the long-term contracts provided a basis for generators to either complete projects which otherwise may not have come on line, or to expedite the completion as compared to the likely later completion given the uncertainty of payment which existed before the Department entered the market. This increased new generation capacity has improved the load and resource balance, helping to reduce spot market prices by increasing capacity reserve margins.
- The market is witnessing entry of new peaking generation over the near term. In addition to accelerating the development or completion of existing projects which were under development prior to the Department's entry to the market in January, the Department has helped assure the near-term development of peaking generation. Starting in February 2001, the Department has been negotiating with parties who had "Summer Reliability Agreements" ("SRA") with the ISO to convert those agreements to bilateral dispatchable peaking agreements with the Department. This conversion was undertaken because of the uncertainty of the ISO's ability to provide payment for the contracts due to the concerns about the creditworthiness of

the IOUs, who would have been responsible for payment of the capacity under the contracts. In addition, the Department negotiated contracts with other non-SRA parties for accelerated development of peaking generation for commercial operation in 2001 to increase available peaking capacity to help meet the net short energy requirements.

More detail regarding the genesis of the Department's involvement in the California electricity market, as well as its effect on the marketplace, is provided in Appendix I.

D. BREAKDOWN OF THE DEPARTMENT'S REVENUE REQUIREMENTS

The Department's revenue requirement consists of costs associated with power supply under contract with the Department to cover the net short energy requirement, administrative and general expenses, DSM- and conservation-related expenses, costs associated with the Department's short-term purchases to meet the residual net short energy requirements, costs associated with leads and lags in payment for services acquired and provided, and finally, costs associated with the Department's financing activities, including cash reserve requirements. These elements of the Department's revenue requirement are categorized as shown below. The first 14 categories are consistent with the cost categories described in the Department's August 7 revenue requirement filing. The additional three categories provide detail to more completely explain the cost components, rather than aggregate these components into the original 14 categories.

Revenue Requirement Categories

1. Costs associated with the purchase and delivery of power;
2. Costs for fuel, including storage and transportation, options, and related financial instruments;
3. Costs that avoid or minimize the amount of power acquired;
4. Payments under security arrangements;
5. Administrative, general, and overhead expenses;
6. Insurance premiums;
7. Payments for employee benefits;
8. Legal and engineering expenses;
9. Other consulting and technical services;
10. Charges for licenses, orders, or other governmental mandates;
11. Taxes and other governmental charges;
12. Expenses, liabilities, compensation of trustees, and other fiduciaries;
13. Costs of complying with any rebate requirements relating to the long-term bonds;
14. Deposits to fund or replenish operating reserves;
15. Debt service payments;
16. Lead (lag) effects in comparison to accrual; and
17. Allowance for uncollectibles.

Costs Associated with the Purchase and Delivery of Power

a. <u>Long-Term Purchases</u>: "Long-term" purchases are those that are more than 90 days in duration. The costs associated with long-term purchases under contracts in existence as of October 1, 2001 are a component of the column labeled "Contract Power" in Table 1 presented in Section B of this filing. An estimate of the energy associated with long-term purchases is a component of the column labeled "Contracts" in Table 2 below. Appendix V provides more detail on how the costs have been computed within the Department's computer model, i.e., PROSYM.[1]

b. Short-Term Purchases: "Short-term" purchases generally consist of bilateral contracts with a duration of 90 days or less but longer than day-ahead purchases, and, for contracts in place as of October 1, 2001, are a component of the column labeled "Contract Power" in Table 1 in Section B. An estimate of the energy associated with short-term purchases is a component of the column in Table 2 labeled "Contracts." Appendix V provides more detail on how these costs have been computed within the Department's computer model.

c. Termination Payments and Liquidated Damages. Termination payments are those applicable on account of termination of contracts prior to the end of the term of the agreement. Liquidated damages are generally payment of monies by either a buyer or seller in accordance with a contract's provisions, rather than as the result of lawsuit or settlement. No termination payments or liquidated damage costs have been assumed in the Department's revenue requirement.

d. Emission Costs: Allowances for emission costs are included in the generation dispatch model and, therefore, included in the estimated cost of power.

e. Day-Ahead and Hour-Ahead Power Costs: Day-ahead and hour-ahead purchases are two of the components of the columns labeled "Residual Net Short" in Table 1 and "Residual Net Short Purchases" in Table 2. These are purchases required to meet demand not satisfied in advance under "long-term" or "short-term" contracts.

TABLE 2
ESTIMATED DEPARTMENT ENERGY PURCHASES
(GWH)

	Total Net Short Purchases	Contracts	Residual Net Short Purchases
Q3 2001	16,054	6,929	9,125
Q4 2001	11,910	5,621	6,289
Q1 2002	10,153	5,466	4,687
Q2 2002	8,648	4,391	4,257
Q3 2002	13,399	7,660	5,739
Q4 2002	11,788	7,239	4,549

f. Real Time Power Costs: Real time power is the final component included in the column labeled "Residual Net Short" in Table 1 and "Residual Net Short Purchases" in Table 2.

g. Transmission, Distribution, and Scheduling Costs: Transmission- and distribution-related costs have not been included in the Department's

[1] PROSYM is a proprietary wholesale electricity market clearing price modeling tool licensed to Navigant Consulting, Inc. by Henwood Energy Systems, Inc.

revenue requirement and are presumed to be covered by the IOU's own rates, consistent with the Department's understanding of the apparent intent of existing Commission decisions. An allowance for transmission and distribution line losses has been provided in the calculation of net short required to be purchased in order to meet the Customers' energy requirements. The estimate of line losses incorporated in the Department's revenue requirements is provided in Table 3 below.

TABLE 3
TRANSMISSION AND DISTRIBUTION LINE LOSS FACTORS

	PG&E	**SCE**	**SDG&E**
Transmission	7.6%	6.5%	5.0%
Distribution	1.4%	1.5%	1.5%

The IOUs are responsible for the costs associated with scheduling their loads with the ISO. Also, sellers are responsible for their costs of scheduling generation to meet load. To the extent that the Department has some costs associated with coordination and scheduling, such costs are captured in administrative and general expenses (or the column labeled "A&G" in Table 1).

h. Ancillary Service Costs: The costs of ancillary services were estimated using a percent of supply cost methodology. For the period starting October 1, 2001, total ancillary service costs are assumed to be equal to the product of (a) 3.7 percent of total IOU retail energy requirements times (b) the projected market clearing price of energy per MWh.[2] The costs shown under the heading labeled "Ancillary Services" in Table 1 represent the projected ancillary service cost for the Department. It is assumed that each IOU will be responsible for grid management charges and other miscellaneous ISO charges other than those shown in Table 4, by ISO charge number.

Appendix IV provides more information on the resources and contracts which, when taken together, comprise the Department's portfolio to meet a portion of the net short requirement. During the Revenue Requirement Period, that portion of the net short that is not met through the contracts summarized in Appendix IV will be acquired by the Department through the spot market.

[2] The 3.7 percent estimate is derived from a historical relationship between ancillary service prices and the historical PX or spot price observed over the period 1999-2000. The derivation of ancillary service costs relies on two assumptions: (1) the IOU's continue to self-provide ancillary services at historical levels from their retained generation, and (2) the IOU's and the Department work cooperatively on scheduling of IOU-retained generation and the Department's resources to minimize overall costs.

TABLE 4
SUMMARY OF DEPARTMENT ISO COST RESPONSIBILITIES

Charge Category	DWR Responsibility of Charge Types	Comments
Ancillary Services		
Regulation Up	5, 55, 115	1. Utility shall schedule URG for energy and ancillary service (A / S) in cooperation with the Department to minimize costs to utility customers. 2. Any available energy or A / S capacity in excess of bundled customer load and inter-utility contracts shall be made available to other IOUs at cost, not paid at ISO market clearing price. (Excess quantity of capacity in charge types (CT) 1, 2, 4, 5, 6, 51, 52, 54, 55, 56) 3. Department will pay the net short cost of A / S only to the extent the payments to IOUs from ISO for URG A / S capacity (CT 1, 2, 4, 5, 6, 51, 52, 54, 55, 56) exceed the cost allocated by the ISO to IOU load (CT 111, 112, 114, 115, 116).
Regulation Down	6, 56, 116	
Spinning Reserve	1, 51, 111	
Non-Spinning Reserve	2, 52, 112	
Replacement Reserve	4, 54, 114	
Imbalance Energy		
Instructed Energy (IE)	401	1. Any available dispatched energy (IE) in excess of bundled customer load and inter-utility contracts shall be made available to other IOUs at cost. (Excess quantity of energy in CT 401) 2. Department will pay the net short cost of IE only to the extent the payments to IOUs from ISO for IE, UE and UFE (CT 401, 406 and 407) exceed the cost incurred to each IOU for IE, UE and UFE (CT 401, 406 and 407). 3. IE and UFE are not covered for SDGE based on letter agreement 4. Department only assumes responsibility for IE, UE and UFE charges less than or equal to the "reasonable" price authorized by Department to the ISO. NOTE: IE, UE, and UFE can be either a charge or credit for any interval.
Uninstructed Energy (UE)	407	
Unaccounted for Energy (UFE)	406	
Congestion	203, 253, 256, 451, 452	1. Congestion is payable by the Department only for congestion associated with energy scheduled by the Department to meet the net short. IOU utility retained generation-related congestion is responsibility of IOUs 2. No congestion charges included for SDG&E based on restated letter agreement.
Neutrality	1010	PG&E and SCE only
Interest and Penalties	3999	Limited to interest charges due to Department delayed payments and on ISO charges that are Department's responsibility. Department not responsible for any retroactive penalties should FERC or ISO reinstate the penalty waiver retroactively. Department not responsible for future penalties associated with IOU under or over scheduling.
Refunds and Market Adjustments		
Rational Buyer Adjustment	1011	1. DWR is entitled to refunds and market adjustments to the extent that it is responsible for the entire imbalance energy procurement as well as a portion of the A / S capacity requirements. 2. 1061, 1062, 1064, 1065, 1066, 1030, 1480 are not included for SDGE.
RMR Pre-Exemption Refund	1061, 1062, 1064, 1065, 1066	
No Pay Market Refund	1030	
Underscheduled Load Refund	1480	

Costs for Fuel, Including Storage and Transportation, Options, and Financial Instruments

The cost of fuel for the contracted power is included in the columns labeled "Contract Power" and "Residual Net Short" in Table 1. Table 5 below shows the cost of natural gas assumed in the development of both contract power costs as well as the cost of residual net short power resources for the Revenue Requirement Period. Natural gas costs are stated in dollars per million British thermal units ("MMBtu"). Fuel transportation charges are estimated in the generation dispatch model based upon regional location of generating sources. Although the Department may have rights to implement option and financial hedging programs and instruments, no such actions or associated costs are specifically assumed in the fuel costs herein. All fuel costs included in the contracts and the spot market purchases are assumed to be equal to the average spot market price of natural gas. Appendix VI provides more detail on the methodology that was used to develop the forecast of natural gas prices.

TABLE 5
GAS PRICE ASSUMPTIONS
($/MMBTU)

	SoCal Border	Malin	PG&E City Gate
Q3 2001	3.72	3.59	3.87
Q4 2001	3.54	3.01	3.49
Q1 2002	3.55	3.02	3.51
Q2 2002	3.52	2.99	3.47
Q3 2002	3.36	2.86	3.33
Q4 2002	3.78	3.22	3.72

Table 6 below provides information on the resulting average cost of the Department-supplied power by month for the Revenue Requirement Period using the gas price assumptions provided in Table 5 above. Appendix V provides a description of the forecasting model and other key assumptions used in the development of these average power costs.

TABLE 6
AVERAGE NET SHORT ENERGY COSTS
($/MWH)

	DWR Contracts	Residual Net Short	Weighted Average Power Cost
Q1 2001	-	284	284
Q2 2001	132	256	227
Q3 2001	128	124	126
Q4 2001	122	37	77
Q1 2002	117	36	80
Q2 2002	146	31	89
Q3 2002	119	38	85
Q4 2002	113	36	83

Costs to Avoid or Minimize the Amount of Acquired Power

Table 7 below provides a breakdown of actual and expected DSM costs by quarter for the Revenue Requirement Period. The Department has included costs and associated energy savings for 2002 only for energy conservation and load management programs that have been authorized by either Executive Order of the Governor or through legislative authorization. No such programs involving funding by the Department as part of the net short energy procurement program have been authorized for 2002 and, therefore, no costs have been assumed. Any net short energy requirements (after the effects of conservation or DSM programs funded by the IOUs or others) are assumed to be met either by energy from the Department's contract purchases or spot market purchases.

TABLE 7 COSTS TO AVOID OR MINIMIZE THE AMOUNT OF ACQUIRED POWER (MILLIONS OF DOLLARS)				
	Conservation Programs	**Load Curtailment/ Interruptible Programs**	**Conservation Rebates**	**Load Management Programs**
Q1 2001	-	-	-	-
Q2 2001	2.3	-	87.5	-
Q3 2001	4.6	-	262.5	-
Q4 2001	-	-	-	-
Q1 2002	-	-	-	-
Q2 2002	-	-	-	-
Q3 2002	-	-	-	-
Q4 2002	-	-	-	-

Appendix II and Appendix VI provide more detail on these programs in terms of the description of the programs, the amount of savings in MWh per month, and the associated costs for these programs and savings.

Administrative, General and Overhead Expenses

The Department's administrative and general expenses are provided in Table 1 in Section B, and as summarized by month in the column labeled "A&G." Table 8 below provides more detail on the administrative and general expenses of the Department.

TABLE 8 ADMINISTRATIVE, GENERAL, AND OVERHEAD EXPENSES (MILLIONS OF DOLLARS)				
	Labor (Including Benefits)	**Capital Expenditures**	**Professional Service Fees**	**Other Administrative and General Expenses[1]**
Q1 2001	$ 1.6	$ 0.6	$ 5.0	$ 2.3
Q2 2001	1.6	0.6	5.1	2.3
Q3 2001	1.6	0.6	5.0	2.3
Q4 2001	1.7	0.6	5.1	2.4
Q1 2002	2.3	5.4	6.4	0.9
Q2 2002	2.3	5.4	6.4	1.0
Q3 2002	2.3	5.4	6.4	0.9
Q4 2002	2.4	5.4	6.4	1.0
Total	$15.8	$24.0	$45.8	$13.1
(1) Other Expenses include costs of administration and billing related to the 20/20 Program in 2001.				

Other Revenue Requirement Components

- **Security Agreement Payments**: There are no specific security agreement payments included in the Department's estimate of its revenue requirements.

- **Insurance Premiums**: Insurance premiums are included in Other Administrative and General Expenses described in Table 8.
- **Employee Benefits**: Payments for employee benefits are estimated as a percentage of total administrative and general expenses and are included in the Labor Including Benefits column described above in Table 8.
- **Legal and Engineering Services**: Expenses related to legal and engineering services estimated at approximately $13.3 million and are included in Professional Service Fees described above in Table 8.
- **Consulting and Technical Services**: Expenses related to consulting and technical services are estimated at approximately $32.8 million and are included in Professional Services Fees described above in Table 8.
- **Licenses, Orders or Other Governmental Mandates**: There are no specific charges for licenses, orders, or other governmental mandates estimated or included in the Department's revenue requirement.
- **Taxes or Governmental Charges**: There are no known applicable taxes or governmental charges which are capable of being estimated as of the date of this filing, and none were included in the Department's revenue requirement.
- **Compensation of Trustees and Fiduciaries**: Any charges associated with expenses, liabilities, or compensation of trustees and other fiduciaries are anticipated to be those associated with issuance of the Department's long-term bonds and would be included in the cost of issuance of the Bonds.
- **Rebate Requirements Associated with the Bond Financing**: No costs of complying with any rebate requirements associated with the bond financing are included during the Revenue Requirement Period.

Debt Service Payments

These costs are included in the Department's revenue requirement and are displayed in the column labeled "Financing Cost" in Table 1 in Section B. In this filing, debt service payments represent principal and interest payments on a $4.3 billion interim financing entered into by the Department on June 26, 2001. This interim financing will be retired from the proceeds of long-term bonds, which the Department expects to issue during the second quarter of 2002. Even though the Department expects to retire the interim financing with bond proceeds during 2002, the terms of the interim financing require the Department to include the debt service costs of the interim financing for the entire period of the filing to protect the lenders from exposure should bonds not be issued.

Interim financing principal and interest payments included in the revenue requirement filing are shown in Table 9, below.

TABLE 9 INTERIM LOAN COSTS (MILLIONS OF DOLLARS)			
	Interest	**Principal**	**Total**
Q3 2001	$ -	$ -	$ -
Q4 2001	-	-	-
Q1 2002	27.3	-	27.3
Q2 2002	81.7	389.5	471.2
Q3 2002	77.9	389.5	467.4
Q4 2002	74.8	389.5	464.3
Total	$ 261.7	$ 1,168.5	$ 1,430.2

Deposits to Fund or Replenish Operating Reserves

The fund in which the operating reserves for the Department's power purchasing activities are held, and into which program revenues are deposited, and from which program expenses are paid, is defined as the "Power Fund." The Power Fund balance currently reflects the unexpended proceeds of the Department's interim financing. The fund balance of the Power Fund is projected to grow during the period of this filing due to the need to make interim financing principal and interest payments and provide debt service "coverage" for the interim financing as more fully described in Section F under the heading "Changes to Debt Service and Financing Related Assumptions."

Operating reserves will need to be replenished only if costs are significantly higher than the assumptions which underlie the Department's revenue requirement as presented in this filing.

Lead (Lag) Accrual to Cash

Lead (lag) accruals to cash are included in the Department's revenue requirements to account for the difference in time between the provision of services to the Customers and the receipts of cash from them. Such amounts, totaling about $107 million (lag), for the Revenue Requirement Period are included in Table 1 under the column labeled "Lead (Lag) Accrual to Cash." Leads (lags) are also used to adjust the Department's total operating costs to derive the Department's total operating expenditures.

These leads or lags can vary depending on the type of expense lead (i.e., payments by the Department for its contractual commitments vs. payments for purchases of residual net short vs. payments by the Department to its other suppliers) and the revenue lag (i.e., the average amount of time it takes the Department to receive payment for services provided). Some of the expense lags are defined within contracts or per the rules of the markets from which the Department arranges for purchases of residual net short. For the purpose of calculating the Department's revenue requirement, a revenue lag of 45 days was assumed for all prescheduled purchases by the Department. Revenue for all purchases by the ISO going forward are assumed to lag 90 days. Revenues attributed to ISO real-time and out-of-market purchases which have been procured for grid reliability have not been paid to date. Revenues attributable to such purchases are assumed to be fully paid by February 2002. Expense lags are assumed to be as follows:

- Contract expenses are assumed to be paid in 20 days[3];
- Pre-scheduled residual net short energy (day-ahead, hour-ahead, and short-term contracts) are assumed to be paid in 8 days; and
- Other expenses are assumed to be paid in 20 days.

Allowance for Uncollectibles

Included in the Department's revenue requirements is an allowance for uncollectible accounts. The allowance for uncollectible accounts was developed based on the Department assuming a pro-rata share of recently observed IOU uncollectible accounts. These amount to $8.2 million for calendar year 2001 and are expected to approximate $16.2 million during calendar year 2002.

[3] While contract terms vary, the Department has been experiencing an average payment lag of 20 days on contract purchases.

E. ACCOUNTING TREATMENT OF REVENUES AND REVENUE REQUIREMENTS

For accounting purposes, the Department has established a Power Fund that considers inflows and outflows of cash from financing costs, Power Purchasing Program costs, total expenditures, revenues realized from Customers, and revenues realized from off-system energy sales of excess Department contract power. Table 10 presents the balance of the Power Fund after considering all inflows and outflows.

The revenue requirement is derived by taking into account revenues other than those realized from the Customers, off-system sales, total program expenditures, and debt service coverage under "term-out" provisions of the interim financing. The revenue requirement is calculated to ensure both that a reasonable minimum operating reserve balance is maintained in the Power Fund and that revenues from the Customers, plus fund balances minus operating expenses, will equal at least 110 percent of debt service payable under the interim financing. This debt service coverage must be calculated each month for the next 12 months, analyzing Power Fund balances, revenues, operating expenses, and debt service obligations in three-month increments.

This debt service coverage is required under the terms of the interim financing and must be included in the Department's revenue requirement. Even the expectations of the long-term bond issuance during the Revenue Requirement Period to repay the interim financing will not eliminate the need to include the costs of meeting this requirement in the revenue requirement, since the revenue requirement must be implemented prior to the issuance of the bonds. The need to meet this coverage requirement causes the revenue requirement to rise to a level approximately $1.3 billion higher than would otherwise have been necessary had the long-term bonds been issued in calendar year 2001.

In connection with the Power Fund's activities, Table 11 below presents actual historical Department cash receipts from the Customers located in the service area of each IOU for the period January 2001 through September 2001.

TABLE 10
THE DEPARTMENT POWER FUND SUMMARY[1]
(MILLIONS OF DOLLARS)

Period	Beginning Fund Balance	Program Operating Costs on an Accrual Basis	Expenditure Lead (Lag)	Total Operating Expenditures	Financing Cost	Total Cash Expenditures	Customer Revenues on an Accrual Basis	Off-System Sales Revenue	Revenue Lead (Lag)	Cash Revenue	Quarterly Power Fund Cash Flow	Deposits from Appropriations and Interim Financing	Ending Fund Balance
Q1, 2001	$ -	$ 3,847.4	$(1,505.2)	$ 2,342.3	$ (7.7)	$ 2,334.5	$ 770.9	$ -	$ (531.3)	$ 239.6	$(2,094.9)	$2,400.0	$ 305.1
Q2, 2001	305.1	4,731.6	(144.2)	4,587.4	(39.3)	4,548.0	2,038.7	-	(1,143.2)	895.5	(3,652.5)	6,202.2	2,854.8
Q3, 2001	2,854.8	2,358.9	81.9	2,440.7	(49.3)	2,391.4	1,661.6	30.1	(476.3)	1,215.4	(1,176.0)	1,682.8	3,361.6
Q4, 2001	3,361.6	1,097.1	442.5	1,539.6	(42.1)	1,497.5	1,211.4	25.0	120.3	1,356.8	(140.7)	-	3,220.8
Q1, 2002	3,220.8	904.0	1,043.0	1,947.0	(14.2)	1,932.8	1,038.2	24.8	939.0	2,002.1	69.3	-	3,290.1
Q2, 2002	3,290.1	871.4	(20.2)	851.2	434.1	1,285.4	890.1	39.3	25.8	955.2	(330.1)	-	2,960.0
Q3, 2002	2,960.0	1,263.4	(25.0)	1,238.4	435.9	1,674.3	1,373.0	45.9	(257.4)	1,161.5	(512.8)	-	2,447.1
Q4, 2002	2,447.1	1,083.1	20.4	1,103.4	436.3	1,539.7	1,205.8	26.0	202.8	1,434.7	(105.0)	-	2,342.1
TOTAL		$16,156.7	$ (106.8)	$16,049.9	$1,153.6	$17,203.6	$10,189.8	$191.1	$(1,120.2)	$9,260.7	$(7,942.9)	$ -	

[1] Preliminary and subject to change.

TABLE 11 CASH RECEIPTS (MILLIONS OF DOLLARS)				
	Pacific Gas and Electric	Southern California Edison	San Diego Gas and Electric	Total
January 2001	$ -	$ -	$ -	$ -
February 2001	-	-	-	32.7
March 2001	75.0	54.4	77.5	206.9
April 2001	142.9	92.6	15.9	251.5
May 2001	159.4	99.1	18.4	276.9
June 2001	212.9	118.5	35.7	367.2
July 2001	268.0	138.6	30.8	437.3
August 2001	223.3	151.1	27.1	401.4
September 2001	192.3	140.3	14.0	346.5

F. CHANGES TO REVENUE REQUIREMENTS SINCE THE AUGUST 7, 2001 FILING

There have been six major changes to the inputs that drive the Department's revenue requirements:

1 Reductions in future energy deliveries by the Department due to increased participation in direct access by electric end-users. This increase in direct access participation is the result of the Commission's decision to extend the cutoff date for contracting with alternative electricity providers;

2 Increases in the Department's financing obligations resulting from its inability to issue long-term debt due to the Commission's rejection of the proposed rate agreement with the Department, the absence of a Commission rate order for the Department's charges, and the corresponding need to comply with the term-out provisions of the Department's interim borrowing;

3 Changes in the assumptions and reductions in the projected cost of fuel resulting from increased supply and deliverability of natural gas resources;

4 Increases in the Department's load forecast resulting from the elimination of certain DSM programs the Department had previously assumed would be undertaken during 2002;

5 Changes in the Department's projected contract purchases due to changes in the number and type of power supply contracts expected to be in place during 2002;

6 Changes in the methodology for calculating ancillary service costs to reflect recent historical market conditions.

7 Changes in estimated prices received by the Department for sales of its contracted power to wholesale power purchasers ("off-system" sales); and

8 Certain changes in the timing of the receipt of revenues by the Department.

Natural Gas Prices

Table 12 provides information on the assumptions regarding natural gas prices that were prepared in June 2001 and used in the filing of August 7, 2001, compared with those that have been used in the current revenue requirement filing. The primary driver for the change in assumptions is an improved outlook on the supply/demand balance for regional gas supplies that is attributed to several factors, including:

- Decrease in demand for natural gas based on reduced levels of electric generation resulting from conservation, and the economic slowdown;
- Improved levels of gas in California storage reservoirs;
- Improved allocation of gas transportation into southern California; and
- Increase in drilling activity.

A more detailed description of the drivers of the change in natural gas prices is provided in Appendix VI.

TABLE 12 COMPARISON OF NATURAL GAS PRICE ASSUMPTIONS ($/MMBTU)							
	Per Filing of August 7, 2001				Per Current Filing		
	SoCal Border	Malin	PG&E City Gate		SoCal Border	Malin	PG&E City Gate
Q3 2001	7.22	3.61	5.64		3.72	3.59	3.87
Q4 2001	7.68	3.47	5.43		3.54	3.01	3.49
Q1 2002	6.86	3.49	5.46		3.55	3.02	3.51
Q2 2002	6.94	3.63	5.66		3.52	2.99	3.47
Q3 2002	6.75	4.72	6.52		3.36	2.86	3.33
Q4 2002	7.15	5.94	7.15		3.78	3.22	3.72

Changes to the Load Forecast on Account of Direct Access

Table 13 compares the amount of direct access (in gigawatt-hours or "GWh") that was assumed in the filing of August 7, 2001, versus that being used in the current revenue requirement filing.

TABLE 13 ASSUMPTIONS REGARDING DIRECT ACCESS (GWH)		
	Per Filing Dated August 7, 2001	Per Current Filing
Q1 2001	3,603	3,603
Q2 2001	607	612
Q3 2001	478	6,751
Q4 2001	448	5,891
Q1 2002	425	5,602
Q2 2002	434	5,756
Q3 2002	473	6,671
Q4 2002	444	5,819

The reason for the dramatic increase in the estimated amount of direct access is the Commission's decision to suspend direct access effective September 20, 2001.[4] In the Department's revenue requirement filing dated August 7, 2001, it was assumed that direct access would be suspended as of July 1, 2001, consistent with the Commission's draft decision issued on June 15, 2001.[5]

Between July 1, 2001 and August 31, 2001, actual direct access loads increased from 2 percent of IOU retail loads to 5.7 percent of IOU retail loads.[6] Additionally, discussions with each of the IOUs indicated that they had a significant number of additional direct access service requests ("DASR") to process as of the time of this filing.

[4] The Commission decision D01-09-060 "Interim Opinion Suspending Direct Access", Issued September 20, 2001.

[5] The revised draft decision sent on August 27, 2001, also stated July 1, 2001 as being the effective date for suspension of direct access.

[6] Data supplied by the Commission.

The direct access loads used in this filing were obtained by asking each of the IOUs for estimates of pending direct access loads. The IOUs reported the information shown in Table 14,[7] below.

TABLE 14 DIRECT ACCESS LOADS			
	DA Load %	**DASR Load %**	**Total %**
PG&E	4.7	5.9	10.6
SCE	5.4	8.5	13.9
SDG&E	17.4	3.5	20.9
Total IOU	6.2	6.8	13.0

Changes to the Revenue Requirement and Load Forecast on Account of DSM

Table 15 compares the energy reductions and program costs for load management and the 20/20 conservation program for this filing and the August 7 filing.

TABLE 15 CHANGES TO THE LOAD FORECAST ON ACCOUNT OF DSM				
	Per Filing Dated August 7 2001		**Per Current Filing**	
	Cost (Millions of $)	**Energy Savings (GWh)**	**Cost (Millions of $)**	**Energy Savings (GWh)**
Q1 2001	$ -	-	$ -	-
Q2 2001	114	474	87.5	474
Q3 2001	338.4	1,422	262.5	1,422
Q4 2001	-	-	-	-
Q1 2002	-	-	-	-
Q2 2002	102.8	474	-	-
Q3 2002	308.4	1,422	-	-
Q4 2002	-	-	-	-

The Department has decided not to engage in demand relief and demand bidding programs and has deferred any decision on whether to implement a 20/20 or comparable program for the summer of 2002. This reduces the revenue requirement by approximately $513 million during 2002. The estimated 20/20 program effects in 2002 were also eliminated from the load forecast, resulting in an increase of 1,896 GWh in 2002 loads.

Changes to the Amount of Department Contracted Power

Since the filing dated August 7, 2001, the Department has entered into additional contracts totaling approximately 156 MW that is expected to be available to meet summer peak lead in 2002. Appendix IV provides more detail on the differences in the number of contracts to supply net short power between the filing dated August 7, 2001, and the current filing.

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[7] Conversations with each of the IOUs on September 28 and October 1, 2001.

Changes to the Methodology for Calculating Ancillary Service Costs

The Department's ancillary service cost responsibility is estimated monthly using a proxy for procured capacity and composite ancillary service market prices, and then adjusted for other ancillary services charge responsibilities not incorporated therein. The Department's model uses data collected from June 1999 through November 2000 to compare (1) monthly historical ancillary services capacity procured on the market (including self provision) to the monthly system load, and (2) the monthly composite ancillary services price to the spot market price. Historical ancillary services market capacity was calculated as approximately 13 percent of load for the period. Historical ancillary services composite price (weighted average of spin, non-spin, regulation up, regulation down, and replacement reserves) was calculated as approximately 31 percent of spot market prices. An adjustment was made to account for the expected amount of self-provided ancillary services costs during the Revenue Requirement Period for which the Department would not bear cost responsibility, estimated as approximately 50 percent.

Other ISO Charges

The Department will incur responsibility for neutrality and unaccounted for energy ("UFE") for PG&E and SCE only. Cost allocations agreed to between the Department and SDG&E excludes these changes as part of the Department's responsibility. The Department is currently in negotiations with the IOUs regarding other non-market based charges for which the Department may bear responsibility. It is not anticipated that the outcome of these negotiations will have a material impact on ancillary services and other ISO changes.

Changes to Debt Service and Financing Related Assumptions

Since the filing dated August 7, 2001, a number of events have occurred that materially change the assumptions regarding debt service and other financing costs. Most notable is the impact that the continued delay in the issuance of long-term bonds will have on the Department's interim financing.

The interim financing executed on June 26, 2001 was structured with both taxable and tax-exempt components. The taxable portion was approximately $2.3 billion, while the tax-exempt portion made up the remaining $2.0 billion. The financing was structured as a term loan due to be paid on or before October 31, 2001, from the proceeds of the long-term Bonds. In the absence of a long-term bond issuance by October 31, 2001 the interim financing was structured to convert to a three-year term loan with quarterly principal and interest payments. Since the Bonds will not be issued by the October timetable originally contemplated by the interim financing, the financing will convert to a three-year term loan on October 31, 2001. The first interest and principal payments will be due in March and April 2001, respectively.

On October 2, 2001, the Commission voted not to approve a rate agreement with the Department, the purpose of which was to formalize the mechanics and time frames relating to the Department's revenue requirement filings and the required rate setting actions of the Commission. The failure of the Commission to execute the rate agreement by October 10, 2001 triggered an increase in interest costs under the terms of the interim financing. Effective October 11, 2001, the interest rate on the interim financing increased by 2 percent because no rate agreement was in place. The 2 percent increase in rates will be in addition to other interest penalties the State will pay when the interim financing converts to a term loan on October 31, 2001.

Until the Department completes the sale of long-term bonds, debt service obligations on the interim financing (principal and interest) will continue to be paid on a quarterly basis, and need to be included in the Department's revenue requirement filings. The interim financing also requires the Department to submit revenue requirement filings that demonstrate that the revenues collected from ratepayers combined with the Power Fund balance will equal at least 110 percent of total operating expenses plus debt service payable under the interim financing. This debt service "coverage" must be calculated monthly for the next 12 months based on the next succeeding three months' revenues and debt service obligations.

The provisions of the interim financing prior to October 31, 2001 and post-October 31, 2001, are summarized in Table 16:

TABLE 16
PROVISIONS OF THE INTERIM LOAN

Provisions Prior to October 31, 2001	Provisions Post-October 31, 2001
Taxable Interest Rate: LIBOR + 75 basis points through October 10 LIBOR plus 275 starting October 11	Taxable Rate: October 31, 2001-April 29, 2002 Base Rate April 30-October 30, 2002 Base Rate + 1% October 31 and thereafter Base Rate + 2% The Base Rate is the higher of Prime or Federal Funds plus 0.5%
Tax-Exempt Interest Rate: 80% of LIBOR + 75 basis points through October 10 80% of LIBOR + 275 basis points starting October 11	Initial Tax-Exempt Rate: Same as taxable rate
	Penalties: Interest rate increases by 2% upon an event of default or an event of non-compliance.
Term: June 26-October 30, 2001	Term: 3 years
Payment Schedule: Full repayment with long-term bond issuance proceeds	Payment Schedule: 11 equal quarterly installments of principal commencing April 30,2002.

While the requirements of the interim financing form the basis for this filing, the Department continues to work toward the issuance of long-term bonds to repay both the interim financing and the State General Fund advances made for power purchases. The Department's total bond issuance is projected to be approximately $12.5 billion. Of that amount, $8.5 billion is expected to be tax-exempt and approximately $4.0 billion will be taxable. The average all-in rate on tax-exempt bonds is currently projected to be 5.42 percent per annum. The average all-in rate for the taxable bonds is projected to be 7.41 percent per annum. The final maturity of the bonds is scheduled to be May 1, 2017. The bond financing is currently structured to have interest funded or "capitalized" from bond proceeds through December 2002. Total capitalized interest is projected to be approximately $419 million. No bond principal amortization is scheduled until May 1,

2005. Deposits for principal payments into the Debt Service Account begin October 2002.

DWR Revenue Collection Assumptions

In previous filings, the Department made certain simplifying assumptions regarding the timing of the receipt of revenues. Key among them was the assumption that revenues collected and currently held by the IOUs to which the Department will be entitled upon the implementation of a rate order allocating those revenues would be remitted to the Department over a 12-month period. With this filing, the Department has refined its modeling to more accurately reflect anticipated schedules for the receipt of these IOU-held revenues and other categories of revenues. The following is an explanation of the refined methodology adopted for this filing.

The Department collects revenues from the Customers based on energy delivered to the Customers. The Department procures that energy in two distinct markets, each with its own time frame between the purchase of energy and the collection of revenues for providing that energy. "Pre-scheduled" energy is purchased by the Department directly from a wholesale supplier. "Out-of-market," or "OOM," energy is purchased through a clearing market (the ISO).

Pre-Scheduled Energy

The Department began billing the IOUs for pre-scheduled energy after the PUC took initial rate action on March 27, 2001. Pre-scheduled energy includes the following categories of purchases: purchases through long-term and short-term contracts and purchases in the day-ahead and hour-ahead markets.

Energy provided by the Department from January 17, 2001, through March 26, 2001, was billed at IOU generation rates effective at the time. With the Commission's March 27, 2001 rate order, volumes sold to the Customers of PG&E and SCE from that date forward were billed at IOU generation rates plus $0.03 per kilowatt hour, with the intent that the Department would receive the full generation rate plus $0.03 for the volume it provided, plus some portion of the $0.03 increment on the volume of energy provided by the IOUs. However, Customer billing at the higher rate would not begin until June 1, 2001. For pre-scheduled electricity sold for the period from March 27, 2001, through May 31, 2001, the collection by PG&E and SCE for the incremental price ($0.03) would be spread over 12 months.

Since June 1, 2001, PG&E and SCE have been billing and collecting at the higher rate for all energy sold, but only remitting to the Department the funds collected (the generation rate plus $0.03) on volumes provided by the Department. The IOUs have withheld the additional receipts on their own volume of energy sold until a rate order finalizing the portion of the additional collections allocable to the Department is implemented. Once a rate order is implemented, the Department can expect to receive within 30 days the amounts collected and withheld by PG&E and SCE through the date of the rate order. The billing for the incremental price for volumes sold from March 27, 2001, through May 31, 2001, would commence and the Department could conservatively expect to receive these funds spread over the following 12 months. For the remaining pre-scheduled energy sold after the rate order, the Department could expect to receive the full amount due from PG&E and SCE through the normal billing cycle already established.

The Commission acted on September 20, 2001, to implement a rate order for SDG&E that included a rate increase of $0.0146 per kilowatt-hour. The modeling used in this filing assumes that the Department is entitled to receive this full rate increase on power it delivers to Customers in the SDG&E service area beginning October 2001.

Out-of-Market Energy

OOM energy is purchased through the ISO clearing market to ensure that adequate energy is scheduled to meet reliability needs for the ISO power grid. The Department is purchasing adequate OOM energy to meet reliability needs for the entire grid. Some of the OOM energy purchased by the Department is not being used by the Customers, but by other users of the ISO grid. It is estimated that approximately 93 percent of the OOM energy purchased by the Department is provided for the Customers, with the remaining 7 percent being provided to other grid users (primarily municipal power agencies). Because of this, only 93 percent of OOM energy is eligible to be recovered through the Department's rates. The remaining 7 percent will need to be recovered at cost through the ISO settlement process. To date, rates have not been collected on the OOM volumes purchased for, and provided to the IOUs due to discrepancies in the settlement process.

The Department expects that upon completion of negotiations with the IOUs and ISO, the IOUs will remit funds to the Department according to the following schedule for OOM volumes purchased. August 2001 settlements would be received in December 2001, establishing a four-month remittance lag (three months to clear the ISO settlement process, and an additional 30 days to receive funds from the IOUs), along with funds representing the settlements for June and July 2001. The Department would receive the September 2001 settlements in January 2002, along with funds representing the settlements for March through May 2001. Cash for the October 2001 settlements would be received in February 2002, along with the reimbursements for the January and February 2001 settlements. This would bring the ISO current for all past settlements for the Department's OOM purchases.

The impact of these more detailed modeling assumptions is the acceleration of the receipt of certain revenues. These changes are reflected in the results of Table 1 and Table 10.

APPENDIX I

The Department and the California Electricity Marketplace

The history of the restructuring of the California electric energy market in the late 1990's is an important backdrop for putting into context the Department's role in purchasing the net short energy requirements of the Customers. An overview of the market, the mechanics of that market, and the roles of players in that market are important to understanding the changes which have occurred with the implementation of the Act and the Department's procurement of net short energy requirements.

Prior to the restructuring, the IOUs were responsible for constructing a portfolio of power supply resources and the procurement of electric supplies to meet the needs of the Customers in a reliable and efficient manner. The IOUs met these power supply needs through a combination of their own generation capacity and energy from qualifying facilities ("QFs"), long-term bilateral contracts, and spot market purchases. These practices and obligations changed dramatically with the restructuring of the California energy market.

Following a multi-year, multifaceted investigation into the California electric industry, the Commission issued a Final Policy Decision on electric utility restructuring on December 20, 1995, which included among others, the following proposed actions:

- Creation of an ISO for California's transmission system;
- Creation of the PX to serve as a market for generation;
- Phase-in of retail competition;
- Collection of competitive transition charges ("CTCs") from retail customers by the IOUs as a means of recouping stranded costs;
- A mandate that the IOUs divest at least 50 percent of their fossil fuel generating assets; and
- Initiation of the ISO, PX, and limited direct access on January 1, 1998.

<u>Passage of AB 1890</u>

On August 31, 1996, the California State Legislature unanimously approved Assembly Bill 1890 ("AB 1890") in order to implement the Commission's Final Policy Decision. Governor Wilson signed AB 1890 into law on September 23, 1996. Among other things, AB 1890:

- Affirmed the January 1, 1998, start date for the PX and ISO (which was subsequently delayed to March 31, 1998 on account of technical systems difficulties), and initiation of direct access by retail customers;
- Redefined the collection period for CTCs;
- Required the IOUs to freeze their retail electric rates on January 1, 1998 and provide a 10 percent rate reduction for residential and small commercial

customers through the earlier of March 31, 2002 or the full recovery of the respective IOUs' stranded costs; and

- Allowed for the 10 percent rate reduction to be financed through the issuance of rate reduction bonds.

The Power Exchange

The stated intent of the legislature in establishing the PX was to create an independent, non-profit power exchange responsible for administering a competitive electricity market through which electric purchasers could buy and sell energy. The PX was to administer both a day-ahead and hour-ahead market. Initially, the IOUs were required to sell all output of their retained power supply resources to the PX and make all purchases of electric energy needed to serve their retail end-users from the PX. Other suppliers or purchasers could use the PX, but were not required to do so. The PX market-clearing price was established as the price of the highest winning bidder. The price of each energy product bought and sold through the PX was set at the PX market clearing price for that type of product, regardless of the individual prices asked by the field of bidders.

The PX operated two separate energy markets: a day-ahead energy market and an hour-ahead energy market. In the day-ahead market, PX Participants (as discussed later in this section) submitted portfolio bids to buy and sell energy for each hour of the succeeding day. These portfolio bids were submitted to the PX by 7:00 a.m. on the day prior to the actual dispatch day, and used by the PX to derive aggregate supply and demand curves from which the PX established an unconstrained market clearing price and quantity for each hour. Following the conclusion of the day-ahead auction, successful bidders provided the PX with "Initial Preferred Schedules" that reflected the quantities awarded in the auction process. These schedules specified the quantity and location of loads and supplies within the grid. The PX, acting as the Scheduling Coordinator for successful bidders, provided these schedules, which in aggregate had to be balanced with respect to supply and demand in each hour, to the ISO by 10:00 a.m. on the day prior to the dispatch day. Other Scheduling Coordinators representing bilateral transactions submitted their balanced schedules to the ISO in a similar manner.

In the hour-ahead market, buyers and sellers were able to adjust the positions they received in the day-ahead market. This was the only means the IOUs and electric service providers had to modify their day-ahead market positions when demand changed due to weather conditions or supply changed due to plant outages or line de-ratings. The PX hour-ahead market also provided benefits to bilateral market participants who wished to adjust their day-ahead market positions. The PX hour-ahead market involved trading around-the-clock through 24 hourly auctions. PX Participants included the IOUs, Federal and municipal entities, independent power producers, and power marketers, from both within and outside California. In 1999, there were approximately 45 PX Participants certified to trade in the PX markets, with about 35 PX Participants active in the markets on any given day. By 2000, the number of PX participants had grown to nearly 80. On the demand side, the IOUs were the dominant participants within the PX, representing about 95 percent of the load in the day-ahead energy market.

Regulatory Must-Take ("RMT") generation was an important factor in the PX market. RMT resources, which include nuclear units, QFs, and certain hydroelectric units without reservoir storage (known as "run-of-the-river" units), must operate because of existing contracts or regulatory requirements. These facilities were bid into the PX at no cost to ensure their selection in the auction process. As with all other accepted bids, however, the owners of the RMT generation received the market-clearing price for this output. Other resources, which may not be classified as RMT, but whose owners may, for operational reasons, want to be assured of being dispatched, were also bid into the PX at no cost and also received the market-clearing price for their output. These resources typically accounted for approximately 20,000 MW of generating capacity, out of the approximately 1,500 MW to 36,000 MW of total capacity which cleared from time to time through the PX.

In addition to operating the forward energy markets (day-ahead and hour-ahead), the PX also functioned as a Scheduling Coordinator with responsibility for submitting balanced resource schedules to the ISO, providing real-time dispatch instructions to the PX Participants, and performing billing and settlement services for both the day-ahead and hour-ahead markets.

<u>The California Independent System Operator</u>

The purpose of the ISO is to manage the California transmission systems of the Participating Transmission Owners ("PTOs"). With this responsibility, the ISO became the control area operator for the combined control areas previously administered by the IOUs. The ISO is responsible for ensuring that there are sufficient ancillary services (spinning reserves, non-spinning reserves, replacement reserves, and black start capability) to ensure reliable operation of the transmission grid. This function requires the ISO to balance generation and loads within the ISO control area, which generally includes the IOU service territories and the municipal utility service areas within them. It excludes the areas served by Los Angeles Department of Water and Power, Imperial Irrigation District, and the City of Pasadena electric utilities. This load and resource balancing is accomplished through day-ahead, hour-ahead, and real-time purchases within the established market or through out-of-market transactions. The ISO also serves as the security coordinator for the California transmission system. As security coordinator, the ISO monitors reserve levels, bus voltage levels, transmission line flows, and generation levels in real-time so that WSCC minimum operating reliability criteria are not violated. When these criteria are in danger of being violated, the ISO has the authority to take whatever actions are required, including directing load interruptions and generation and load schedule changes, to maintain or restore operation within reliability parameters.

The ISO operates the real-time Imbalance Energy Market, the Ancillary Services Market, and the Transmission Congestion Management Market, as described below.

- Imbalance Energy Market (Real-Time Market). The ISO is responsible for balancing loads and resources in real-time. The ISO uses bids received in the day-ahead and hour-ahead markets to increment (increase levels of generation required to meet higher than anticipated loads or to replace unexpected loss of generation that was scheduled to operate) and decrement (require generators to reduce production because of lower than expected loads or generation output experienced at levels higher than scheduled) resources as needed to maintain a system-wide energy balance. The Imbalance Energy market price is calculated in 10-minute intervals on an ex-post basis. This price is used to settle deviations between scheduled and actual quantities of supply and demand. A Scheduling Coordinator that over-delivers relative to its scheduled quantity, based on system requirements, is paid the imbalance price, while a Scheduling Coordinator that under-delivers relative to its scheduled quantity is charged this price.
- Ancillary Services Markets. The ISO conducts four day-ahead and four hour-ahead auctions for ancillary services. These ancillary services are regulation, spinning reserves, non-spinning reserves, and replacement reserves. Each service is a capacity-only market. Bidders must also include energy bids with each capacity bid. The energy bids in the regulation market are dispatched by the ISO's Energy Management System ("EMS") in merit order of energy bid prices as determined by the EMS, while the energy bids for spinning, non-spinning, and replacement reserves are used, along with Supplemental Energy bids, in the real-time Imbalance Energy Market. In addition to these four ancillary service products, which are acquired through an hourly market-clearing auction process, the ISO also is responsible for acquiring voltage support/reactive supply and black start capability, which it procures though a longer term contracting process.
- Transmission Congestion Management. The Transmission Congestion Management market operates on the basis of Schedule Adjustment Bids ("SABs") provided to the ISO by Scheduling Coordinators. These SABs indicate the willingness of a Scheduling Coordinator to increment a resource if the price increases or decrement a resource if the price decreases (vice versa for demand and exports), and are an expression of the value that the Scheduling Coordinator places on obtaining inter-zonal transmission access. The ISO uses the SABs to adjust individual resource schedules to relieve congestion and calculate Transmission Congestion Usage Charge rates.

After the approval of AB 1890, the IOUs filed applications at FERC related to the implementation of restructuring. Under the Federal Power Act, the ISO, as an independent system operator, is defined as a "public utility" and is subject to FERC jurisdiction. FERC has exclusive jurisdiction over the rates, terms, and conditions of service of the ISO, and the purchase, sale, lease, or other disposition or acquisition of facilities.

Market Changes Following Implementation of AB 1890

As required by AB 1890, the IOUs divested themselves of a substantial portion of their fossil-fuel electric generating assets. Typical buyers of these assets were energy corporations that operated as non-regulated power producers. The output of these assets were then sold into the PX and other markets. Certain of the IOUs' divested generating resources were subject to Reliability Must-Run ("RMR") contracts with the ISO. In general terms, these generating facilities must operate to prevent collapse of the transmission system or to mitigate market power of other generators. These facilities were to be made available to the ISO for reliability needs, unless they were already bid into the PX markets. Typical examples of generating facilities which provided RMR service in southern California were the Alamitos units, each of which ranged from 175 MW to 480MW and the Etiwanda units which ranged in capacity from 132 MW to 320 MW. All of the previous SCE divested generating units which provided RMR service were the steam generating units. In northern California, typical divested PG&E units included the Morro Bay units ranging in capacity from 163 MW to 338 MW, the Potrero units ranging from the 52 MW combustion turbine units to the 207 MW steam unit, and all of the Geysers geothermal units.

During periods when the demand for electricity neared the total available supply of generation, market-clearing prices on the PX increased. By the summer of 2000, the ISO supplies of imbalance energy became scarce during periods of high demand, which required out-of-market purchases (purchases by the ISO outside of the PX market to assure availability of supply) at significantly higher prices than the PX clearing price for electricity. As an example, the PX prices in peak hours during June and July of 2000 averaged about $230 per MWH, while the ISO out-of–market prices during that same period ranged from approximately $450 per MWh to over $650 per MWh.

Prices paid by the ISO for purchases in the same-day market began to exceed the day-ahead PX clearing price. When this occurred, bidding activity was reduced in the PX day-ahead market and the ISO was left to secure significantly higher amounts of generation in the hour-ahead market. Prior to the initial operation of the ISO, the IOUs used their own generation to supply most of their load. Purchases of small amounts of electric energy were made in the day-ahead market if those purchases were economically priced, and were generally made in-lieu of running more expensive resources owned by the IOUs. In the hour-ahead market, the IOUs generally purchased small amounts of energy to balance their supply needs, but only if the price was less than the cost of running one of their own generators. Due to the requirement of AB 1890 that the IOUs divest at least 50 percent of their generating resources, the IOUs were forced to rely on the day-ahead and hour-ahead markets of the PX and ISO for a large portion of their power supply requirements. This reliance made them much more sensitive to changes in short-term energy prices.

By the summer of 2000, the total amount of load and generation (including utility retained generation) scheduled in the PX day-ahead and hour-ahead market consistently hit a plateau of about 35,000 MW, with remaining load above this level being met in the ISO's real-time imbalance market. The ability of buyers to increase purchases in the PX day-ahead market was severely limited by the lack of supply offered in the PX at prices which buyers where willing to accept. The ISO reports that large buyers had an incentive to minimize overall costs by limiting their purchases in the PX market, resulting in massive under-scheduling during times of high loads. This incentive stemmed from price caps of $2,500 per MWh in the PX market, which encouraged buyers to shift load requirements to the ISO imbalance market, where price caps were dramatically lower (ranging from $250 to $750 per MWh during 2000). The ISO attempted to counteract the under-scheduling of buyers by purchasing replacement reserves when forecasted load significantly exceeded the load scheduled in the PX forward markets, thereby attempting to avoid out-of-market purchases (which were not subject to ISO price caps). During the three-day period from June 13 through June 15, 2000, forecasted loads were as high as 45,000 MW, yet the load scheduled in the PX forward energy markets remained at approximately 35,000 MW. The ISO purchased virtually all supplies offered in the markets over the period at prices up to nearly $1,400 per MWh, in part through out-of-market purchases. The ISO reports that during the first two summers of operation, prior to implementation of economic penalties against generators that failed to respond to ISO dispatch orders, real-time energy prices consistently hit the ISO price caps at very high load levels, resulting in diminishing quantities of supplies bid into the imbalance market and the need for increased out-of-market purchases at prices above the market price caps. During this time, PX prices rarely exceeded the ISO price caps due to the limited incentives for buyers to participate in the PX market at prices above this level.

On July 21, 2000, PG&E and SCE filed emergency motions with the Commission seeking authorization to enter into bilateral power contracts through the PX markets. PG&E and SCE stated that such authority was needed on an emergency basis in order to better hedge against the risk of price spikes during high load conditions and to introduce new supply into California. On August 9, 2000, SDG&E filed a similar emergency motion with the Commission seeking authorization to enter into bilateral power contracts. Authorization to enter into such arrangements was granted to PG&E and SCE by the Commission on August 3, 2000, and to SDG&E on September 21, 2000. The Commission's decisions allowed the IOUs to purchase energy and ancillary services and capacity products in the PX bilateral forward markets under contracts that expired on or before December 31, 2005. Cumulatively, the IOUs entered into approximately 850 to 1,200 MW (depending upon the month) of bilateral contracts, the majority of which expired by the end of 2003, and approximately 1,425 MW of PX block forward contracts, with the majority of that capacity under quarterly contracts in the summer months of 2000. All of the PX block forward contracts entered into by the IOUs expire at or before the end of 2001. Even after these bilateral and PX block forward contracts were included in the power supply, the net short capacity requirements in the summer of 2001 typically ranged from 10,000 MW to over 17,000 MW during weekly peaks.

On December 15, 2000, FERC issued an order containing a variety of measures aimed at resolving the problems encountered in the California energy market. Among other features, this order eliminated the requirement that the IOUs sell all of their generation into and buy all of their requirements from the PX. This order also terminated the PX wholesale rate schedules effective the end of the trading day April 30,

2001. These actions were taken to provide the IOUs the opportunity to secure a more diversified power supply resource base and increase the longer-term incentives for the development of new generating resources within the state. Despite these actions, a scarcity of generating resources continued in the California marketplace and energy prices continued to increase.

<u>Impact on IOU Rates and Cost Recovery</u>

Changes in the supply availability and price of wholesale electricity since early 2000 have had a seriously detrimental impact on the IOUs' costs and the adequacy of their revenue recovery. The impact was felt by all three IOUs.

- In June 1999, SDG&E determined that it had fully recovered its stranded costs from its retail consumers. This determination triggered the elimination of the retail rate freeze mandated by AB 1890 for SDG&E. With its rates no longer frozen, SDG&E's overall rates were initially lower, but became subject to fluctuation with the actual cost of electricity purchases. A number of factors, including supply/demand imbalances, resulted in abnormally high energy costs beginning in mid-2000. During the second half of 2000, the average energy cost was 15.51 cents per kilowatt-hour ("kWh") compared to 4.15 cents per kWh in the second half of 1999. In response, legislation enacted in September 2000 (Chapter 328, California Statues of 2000), imposed a ceiling of 6.5 cents per kWh on the cost of electricity that SDG&E could pass on to its small usage consumers on a current basis. Consumers covered under the commodity rate ceiling generally included residential, small commercial, and lighting end-users. The ceiling, which was retroactive to June 1, 2000, extends through December 31, 2002 (December 31, 2003, if deemed by the Commission to be in the public interest). As a result of the legislation, SDG&E is not able to pass through to its small volume end-users on a current basis the full purchase cost of electricity that it provides. The legislation provides for the future recovery of costs in a manner intended to make SDG&E whole (additional legislation was enacted on April 6, 2001, which extended the commodity rate ceiling to all end-users). (The ceiling does not apply to energy provided by the Department.)
- Despite participation in the PX's bilateral forward markets, by late 2000, both PG&E and SCE indicated that they were incurring costs for energy purchases through the PX and ISO which substantially exceeded the level of cost recovery afforded by their retail rates, which were still frozen at 1996 levels. In November 2000, both IOUs applied to the Commission for rate increases to alleviate these under-recoveries. In a decision dated January 4, 2001, the Commission granted PG&E and SCE a temporary surcharge of $0.01 per kWh on retail rates
- Before the Commission made its ruling on the $0.01 per kWh surcharges for PG&E and SCE, several generators that had been selling into the California energy market publicly questioned the financial health of the IOUs, particularly SCE and PG&E. The relief granted by the Commission was insufficient to counteract this sentiment. It is evident that less generation was

offered for sale through the PX. Observers of the market attributed a portion of this reduced level of market activity to concern of generators with the possibility of financial default by the PX, ISO, and/or the IOUs. As supply decreased, the price of electricity offered within the California wholesale market increased further.

- By January 2001, with wholesale prices escalating and retail prices frozen, PG&E and SCE began defaulting on purchased power bills to the PX, ISO, and other power providers. In turn, the PX and ISO could not pay energy suppliers what they were owed. With the IOUs no longer required to participate in the PX power market, PX operations slowed dramatically. During this same period, the ISO began experiencing problems securing needed power supplies to maintain reliable operation of the California transmission system. The PX suspended trading in its power markets on January 31, 2001.

Federal Intervention

On December 13, 2000, the Secretary of the United States Department of Energy ordered certain power suppliers to continue selling to the ISO for an emergency period that was subsequently extended to February 11, 2001. In a July 17, 1998 order, FERC used its authority to regulate wholesale power prices to allow the ISO to set price caps (as described above) to limit the market power that could be exercised by energy providers in the California marketplace. FERC had chosen to allow “soft caps” rather than “hard caps.” A hard cap is defined as the price barrier that cannot be broken for purchases under any circumstance. A soft cap is defined as the price barrier only for the day-ahead market. With a soft cap, there is not an effective price barrier for the hour-ahead market. The result is hour-ahead prices that can exceed the established cap level.

In FERC’s December 15, 2000, order freeing the IOUs from the PX markets, FERC concluded that the California energy market was dysfunctional and the ISO was ordered to replace its Board of Governors (the “Board”). On January 24, 2001, the Governor of California appointed a new five-member Board of Governors for the ISO.

Plan to Stabilize the California Energy Market

In December 2000 and January 2001, the ISO requested the Department, in its capacity of operator of the State Water Project, to assist in avoiding rolling blackouts by purchasing power in the spot market and delivering it to the ISO for redelivery to the IOUs as part of the supply to be made available to the Customers. Several such purchases and deliveries occurred, totaling approximately 68,000 MWh and $39 million. On January 17, 2001, the Governor issued a proclamation under the Emergency Services Act directing the Department to acquire electric energy supplies, separate and apart from the operations and finances of the State Water Project, to assist in mitigating the effects of the energy supply emergency. In conjunction with this proclamation, approximately $440 million of the Department’s general fund appropriations, originally intended for other purposes, was made available to the Department to fund energy purchases. Of this total, approximately $302 million was expended for energy purchases. SB 7X, the first urgency legislation to confirm the Department's responsibilities in the emergency, was passed and signed into law on January 19, 2001, and appropriated an additional $400 million to the Department for power purchases.

The Act, signed into law on February 1, 2001, authorized the Department to purchase electric power to be provided to the Customers. The Act included a direct appropriation of an additional $500 million for that purpose and created a process whereby the Department could request and receive additional "deficiency appropriations" upon 10 days advance written notification to the Legislature. The Act granted certain powers to and establishes certain requirements of the Department in connection with its role as an energy provider. These powers and requirements include, but are not limited to, the following:

- Authorizes the Department to act on behalf of the State of California to secure necessary power supplies for resale to the Customers;
- Requires the Department to retain title to all power sold, but allows it to enter into service agreements with the IOUs for distribution and billing services;
- Authorizes the Department and the Commission to enter into an agreement with respect to charges for power sold or made available by the Department, which agreement shall have the force and effect of a financing order as determined by the Commission;
- Authorizes and entitles the Department to collect all revenue requirements incurred in connection with its activities under the Act, including debt service costs and related debt service coverage requirements, payments under power purchase contracts and spot market purchases, reserves as determined by the Department, and administrative costs, among others, through Customer charges;
- Establishes that the payment for power delivered by the Department is a direct obligation of the Customers; and
- Restricts the Department from entering into new power purchase agreements on or after January 1, 2003, but allows it to continue administering existing contracts and enforcing revenue requirements beyond that date.

<u>Implementation of the Department's Authorization</u>

The Department's power purchase program initially involved the purchase of energy through the spot markets until a plan for development of a portfolio of bilateral purchases, funded conservation, and spot purchases could be developed. Activities which have been initiated by the Department since enactment of the Act include the following:

- Forecasting the electrical needs of the IOUs and the net short requirements of the Customers;
- Entering into contracts for firm, unit contingent, and dispatchable power supplies to meet a portion of the Customers' net short requirements;

- Managing the scheduling of available power supply resources to maximize the economic value of the Department's power supply program;
- Developing programs to increase the availability of cost effective interruptible load control, securing needed generating reserve capacity and, mitigating the risk of future natural gas price and supply volatility;
- Securing needed generating reserve capacity; and
- Mitigating the risk of future natural gas price and supply volatility.

<u>Subsequent Regulatory Actions</u>

On March 27, 2001, the Commission issued an order that authorized a rate increase averaging $0.03 per kWh to be collected from the Customers of PG&E and SCE. The purpose of the rate increase was to generate additional revenues to fund the power supply costs of the IOUs and the Department on a going forward basis. In addition, a portion of the additional revenues were to be used to buy power from the QFs under contract to SCE and PG&E, as many QFs were in danger of ceasing power production due to lack of payment. Under this initial rate order, none of the revenues raised by the rate increase were to be used to repay the remaining IOU obligations to creditors for past power transactions. The March 27 order did not address the specific distribution of the rate increase among the individual rate classes of PG&E and SCE and reserved actual implementation of the rate increase for a future order. The retail electric rates charged by SDG&E were not affected by the Commission's March 27 order.

On April 6, 2001, PG&E filed with U.S. Bankruptcy Court for the Northern District of California (the "Bankruptcy Court") for Chapter 11 bankruptcy protection. PG&E has petitioned the Bankruptcy Court with respect to several aspects of the Commission's regulatory orders and restrictions, but the court has not as yet directly reversed or over-ridden any such Commission action.

Also on April 6, 2001, FERC issued an order requiring that a creditworthy creditor back all ISO transactions with third parties. Pursuant to this order, the Department asked the ISO to issue market notices which announced the Department's assumption of financial responsibility for ISO purchases of ancillary services and real-time energy. To date, the Department has accrued a set-aside of over $1 billion to pay this obligation. Revenues attributable to such energy has not yet been received by the Department.

On April 26, 2001, FERC issued an order establishing a prospective mitigation and monitoring plan for the California wholesale electric market. The proposed plan would remain in effect for a period no longer than one year and would institute a variety of changes in the wholesale electric market, including (i) increased coordination and control of generator outages; (ii) requirements for certain generators to offer power in real time; (iii) identifying the wholesale prices at which load should be curtailed; (iv) establishing a single market clearing price for the real-time energy market; and (v) mitigating prices for available capacity during times of reserve deficiencies. FERC's plan was conditioned on the ISO and IOUs' filing of a regional transmission organization proposal by June 1, 2001. The FERC plan did not include price caps, despite requests by the Governor, several state legislators, and several of California's congressional representatives.

On May 15, 2001, the Commission issued an order establishing rate designs for PG&E and SCE which incorporate the $0.03 per kWh average rate increases authorized in the March 27 order. The new rates are designed to protect low-income consumers and residential users with electric consumption equal to or less than 130 percent of the Commission's baseline amounts from any increase in electric rates. Additional revenues produced by the rate increases will be collected in increasingly greater amounts, according to usage, from consumers within each rate class. The new rates took effect on June 1, 2001, for PG&E and June 3, 2001, for SCE.

On June 19, 2001, FERC issued an order on price mitigation throughout the WSCC. Under this order, a soft price cap is set for the entire WSCC based on the heat rate of the least efficient unit and the average natural gas price during the most recent Stage 1 Emergency ("Stage 1") warning period issued by the ISO. During a Stage 1 (or higher) warning period, the cap is equal to the energy cost resulting from the heat rate of the least efficient resource being utilized in the market and the average natural gas price in California, plus a $6.00 per MWh cost for operation and maintenance expenses. A 10 percent risk premium is added for energy sold in California. If a Stage 1 warning is not in effect, the effective cap is calculated as 85 percent of the last Stage 1 cap in effect. The Stage 1 cap is re-set during each successive ISO Stage 1 warning of 60-minute duration or longer.

On September 20, 2001, the Commission ordered an increase of $0.0145 per kWh in the rates of Customers located in SDG&E's service area. These rate increases are primarily intended to provide revenues to pay the net short energy purchase obligation, including debt service payments, of the Department for Customers in SDG&E's service area.

<u>Subsequent Actions by the Department and other State Administrative Agencies</u>

Several actions have been undertaken by the Department and other administrative agencies within state government with the objective of achieving some level of control over Customer demand and the availability of electrical supply and the price paid for that supply. These actions include, but are not limited to:

- Eliminating the former PX's pricing mechanism, where all bidders in a market (such as the day-ahead market or hour-ahead markets) received the highest price bid into and accepted by the market, and replacing it with a "pay-as-bid" purchasing method, where each successful bidder received the bid price it actually submitted;
- Competitively soliciting long-term, bilateral contracts that enable suppliers to discount the near-term cost of electricity in exchange for certainty of contract sales volumes and the ability for both the Department and the power suppliers to lock in gas forward contracts at prices well below the then in effect gas prices in the spot market;

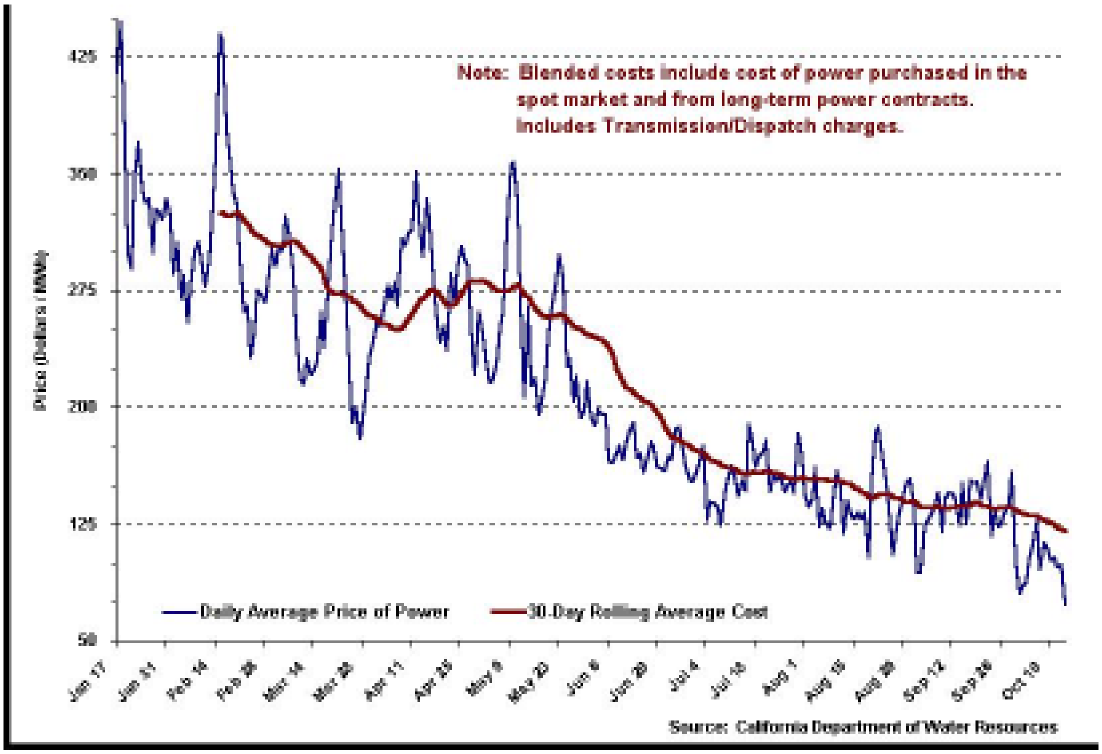
- Establishing more proactive trading desk practices to achieve a wider range of short-term purchases, from day-ahead to weekly, balance of month, monthly, or longer term on a negotiated pay-as-bid basis to limit exposure to the day-ahead, hour-ahead, and imbalance market prices;
- Planning and implementing several energy efficiency and other conservation programs, such as efficient appliance replacement rebates, so-called "cool roof" programs to reduce major building heat gain, and rebate programs for achieving certain levels of energy conservation month-over-month for 2001 compared to 2000;
- Funding various voluntary summer peak period load curtailment programs to make significant payments to large electric end-users for load reduction during periods of high demand and potentially impending shortage of supply;
- Modifying the energy price formula for QF contractors with the objective of better tracking actual natural gas prices against the costs of gas-fired QFs to enable them to supply Customer needs, particularly for the 2001 summer season;
- Creating a new accelerated 21-day permitting process for new peaking generation which can come on line in summer 2001; and
- Contracting with developers of peaking facilities that are willing to accelerate development of new peaking generation.

Since initiation of the above efforts, the wholesale electric market in California has changed dramatically. As shown in Figure I-1 below, prices for combined long-term and short-term purchases of electricity have dropped substantially over the period January 17 through October 10, 2001.

As shown in Figure I-1, the impact of the above actions has been dramatic:

- The average daily price of net short energy has fallen from over $450 per MWh to less than $150 per MWh by the end of September and prices have fallen further in early October. As a result, daily net short energy purchase costs have fallen from as high as over $100 million per day to less than $20 million per day by the end of September.
- Reduction of demand through conservation and the satisfaction of a significant portion of remaining demand with generation committed under longer term contracts has increased the percentage of capacity reserve in relation to the portion of demand that remains to be satisfied, creating a more competitive market for the satisfaction of that remaining demand, thereby resulting in further reduced spot and forward market prices.
- Even before the June 19, 2001 FERC market mitigation order establishing soft price caps, during 100ºF + weather, spot market prices had dropped to below $100 per MWh compared to the May average spot price of over $270 per MWh due to combination of conservation and the Department's contracts.

FIGURE I-1
AVERAGE COST OF POWER



- Spot prices have stabilized at prices averaging approximately $60 per MWh even during days with typical high summer temperatures.
- There has not been a blackout in California since May 8, 2001, despite predictions earlier this year by market observers of over 300 hours of blackouts for this summer.
- Sellers have recognized the Department's creditworthiness, with a number of long-term contracts executed and market participants continuing to sell to the Department in the spot market.

Also, the commitment of generating resources to meet the needs of electric consumers in the California electric market has increased materially. Starting in February 2001, the Department has been negotiating with parties who had "Summer Reliability Agreements" ("SRA") with the ISO to convert those agreements to bilateral dispatchable peaking agreements with the Department. This conversion was undertaken because of the uncertainty of the ISO's ability to provide payment for the contracts due to the concerns about the creditworthiness of the IOUs, who would have been responsible for payment of the capacity under the contracts. In addition, the Department negotiated contracts with other non-SRA parties for accelerated development of peaking generation for commercial operation in 2001 to increase available peaking capacity to help meet the net short energy requirements. As a result of this effort, approximately 1,150 MW of new peaking resources were added to the generation capability within California in 2001.

APPENDIX II

Short-Term Load and Energy Forecast

This appendix describes the load and sales forecast used for this revenue requirements filing. The starting point was the forecasts of 2001 loads prepared by each IOU during 2000[8] and used as their standard test year forecast in FERC and Commission filings, including Commission Decision 01-03-081. Since the forecasts were developed during 2000, they do not reflect the changes resulting from the electricity supply crises in the last half of 2000 and first half of 2001. The IOU forecasts were adjusted by the Department for a number of factors, including:

- **Elasticity of Demand** – the 20 to 40 percent price increases implemented in 2001 will cause some reduction in demand;
- **Energy Crisis Conservation** – consumers and businesses reduce use during times of crisis in response to public appeals and to be good citizens by helping out;
- **Distributed Generation** – smaller generation resources which can be developed by or for utility customers to serve customer loads rather than relying upon supply from a utility or an electric service provider. The supply crisis, higher electricity prices, and significant state initiatives to encourage distributed generation will result in more distributed generation being developed than was foreseen when the utility forecasts were prepared in 2000;
- **Programmatic Conservation** – Assembly Bill 970 (“AB 970”), Senate Bill 5X (“SB 5X”), and Assembly Bill 29X (“AB 29X”) provided substantial additional funding for conservation in the last quarter of 2000 and in 2001;
- **Direct Access** – direct access loads declined sharply as many electric service providers (“ESP”) exited the market during the period of high market prices because they could not compete with the frozen retail rates. Subsequently,

[8] These 2001 forecasts of monthly loads had been used by the IOUs as their standard test year forecast in FERC and the Commission filings, including Commission Decision 01-03-081. The Department obtained, from the Commission and from the IOUs, the most recent IOU load projections available during the first quarter of 2001. For PG&E, the Department used the forecast prepared in May 2000 for PG&E’s 2000 Revenue Adjustment Proceeding filing with the Commission. PG&E used this forecast in several subsequent rate proceedings, including (i) its November 2000 Rate Stabilization Plan; (ii) the Commission proceedings to calculate the California Procurement Adjustment established by the Act; and (iii) FERC proceedings requesting an increase in authorized transmission rates. For SCE, the Department used the forecast developed in March 2000. SCE used this forecast in its September 2000 filing with the Commission for the SCE’s Test Year 2002 GRC. For SDG&E, the Department used the forecast prepared by SDG&E in late 2000. This forecast was the source of the billing determinants used in rate proceedings before the Commission in March 2001. PG&E’s economic forecast was based on a Data Resources Inc. (“DRI”) forecast of economic growth in PG&E’s service area. SCE derived its economic assumptions from a national and statewide forecast prepared by DRI, while SDG&E relied on a DRI forecast of economic trends in its service area. These forecasts projected that the economies in all three IOU service areas would continue to expand in 2001 and 2002, although at a substantially lower rate than in 1999 and 2000, e.g., with an approximately 30% lower employment, growth rate.

many customers have returned to direct access as increases in the IOUs' retail rates have been authorized by the Commission; and

- **20/20 Program** – the 20/20 program, established by Executive Order, provides a monthly credit to customers who reduce their electricity use during the months of June through September, 2001, by 20 percent relative to the same month of the previous year.

The initial IOU load forecasts were adjusted for each of these factors, as described below. Table II-1 summarizes the IOU retail energy forecasts for 2002 used for this revenue requirement and for the August 7 revenue requirement.[9]

TABLE II-1
ENERGY FORECASTS
(GWH)

	2002	
	Oct. 17 Filing	**Aug. 7 Filing**
PG&E		
Gross Sales	83,631	83,631
Losses	(7,527)	(7,527)
Gross Energy Requirements	91,158	91,158
Elasticity Reduction	(2,735)	(2,735)
Energy Crisis Conservation	(3,646)	(3,646)
Distributed Generation	(707)	(707)
New Programmatic Conservation	(2,169)	(2,169)
Direct Access Sales	(8,632)	(759)
20/20 Program	--	(860)
WAPA Purchases	5,429	5,429
Net Energy Requirements	78,697	85,711
SCE		
Gross Sales	85,456	85,456
Losses	(6,836)	(6,836)
Gross Energy Requirements	92,292	92,292
Elasticity Reduction	(2,769)	(2,769)
Energy Crisis Conservation	(3,692)	(3,692)
Distributed Generation	(716)	(716)
New Programmatic Conservation	(2,197)	(2,197)
Direct Access Sales	(11,427)	(876)
20/20 Program	--	(868)
WAPA Purchases	--	--
Net Energy Requirements	71,492	81,175
SDG&E		
Gross Sales	18,966	18,966
Losses	(1,233)	(1,233)
Gross Energy Requirements	20,199	20,199
Elasticity Reduction	(606)	(606)
Energy Crisis Conservation	(808)	(808)
Distributed Generation	(138)	(138)
New Programmatic Conservation	(424)	(424)

[9] Estimates of PG&E's peak demand and energy requirements include requirements associated with PG&E's contract 2948A with the Western Area Power Administration ("WAPA"). Under this contract, PG&E is obligated to supply that portion of WAPA's load (primarily governmental and municipal sales) that exceeds the output of the hydroelectric generating facilities constructed by the Central Valley Project. PG&E's obligation varies by year due primarily to hydrological conditions and WAPA's load levels. PG&E estimates that under average hydrological conditions, its obligations under the WAPA contract will total 5,534 GWh per year. This contract expires at the end of 2004. This WAPA requirement is part of PG&E's total resource requirements.

TABLE II-1
ENERGY FORECASTS
(GWH)

	2002	
	Oct. 17 Filing	**Aug. 7 Filing**
Direct Access Sales	(3,789)	(141)
20/20 Program	--	(168)
WAPA Purchases	--	--
Net Energy Requirements	14,434	17,914
Total – All IOUs		
Gross Sales	188,052	188,052
Losses	(15,596)	(15,596)
Gross Energy Requirements	203,648	203,648
Elasticity Reduction	(6,109)	(6,109)
Energy Crisis Conservation	(8,146)	(8,146)
Distributed Generation	(1,561)	(1,561)
New Programmatic Conservation	(4,790)	(4,790)
Direct Access Sales	(23,848)	(1,776)
20/20 Program	--	(1,896)
WAPA Purchases (PG&E Only)	5,429	5,429
Net Energy Requirements	164,623	184,800

Adjustments in Forecasted Loads and Resources Between August 7, 2001 and the Current Filing

Two major adjustments were made in the forecast of loads and energy subsequent to the August 7 filing:

- **Substantial increase in the amount of Direct Access** – the Commission Decision 01-09-060 (September 20, 2001) suspended direct access effective September 20, 2001. In the August 7 filing, it was assumed that direct access would be suspended as of July 1, 2001, consistent with the draft decision issued on June 15, 2001.[10] Between July 1, 2001 and August 31, 2001, representatives of the IOUs indicated that actual direct access loads increased from 2 percent of IOU loads to 5.7 percent of IOU loads.[11] Discussions with each of the IOUs indicated that they had a large number of additional DASRs to process.

The direct access loads used in this filing were developed by asking each of the IOUs for estimates of pending direct access loads. The IOUs reported the estimates of direct access loads[12] and pending DASRs as of September 20, 2001 shown in Table II-2 below.

[10] The revised draft decision sent on August 27, 2001 also stated July 1, 2001 as being the effective date for suspension of direct access.
[11] Data supplied by the Commission
[12] Conversations with each of the IOUs on September 28 and October 1, 2001.

TABLE II-2 DIRECT ACCESS LOADS AND PENDING DASR'S			
	DA Load %	**DASR Load %**	**Total %**
PG&E	4.7	5.9	10.6
SCE	5.4	8.5	13.9
SDG&E	17.4	3.5	20.9
Total IOU	6.2	6.8	13.0

- **Elimination of 20/20 program in 2002 --** Consistent with the Department's decision to terminate, for the time being, its participation in certain conservation programs as noted in the Department's September 10, 2001 comments on the Commission's September 4, 2001 Draft Decision ("DD") Implementing the Department's Revenue Requirement, all costs for load management programs and for the 20/20 program in 2002 have been eliminated from the revenue requirement. This reduces the revenue requirements during 2002 by $513 million. The estimated 20/20 program effects in 2002 were also eliminated from the forecast, resulting in an increase of 1896 GWh in 2002 loads. The increase in energy requirements is assumed to be met by additional short-term energy purchases.

<u>Price Elasticity Adjustments</u>

Loads were reduced to account for response to higher electricity prices. Starting in June 2001, loads were reduced by 2 percent following the 3 cents per kWh average rate increase implemented in June. It was assumed that the price response would increase to a 3 percent load reduction starting in January 2002. That is, it would take 6 months before the full price response is observed.

This elasticity adjustment is based on an average 30 percent rate increase and a price elasticity of -0.1. SCE uses price elasticities of -0.105 and -0.044 for the commercial and industrial sectors, respectively in its sales forecast model.[13] PG&E used long run price elasticities of -0.1, -0.125, and -0.150 for residential, commercial and industrial consumers, respectively.[14] The SCE industrial price elasticity excluded direct access, the amount of energy which customers would obtain from sources other than SCE, such as through self-generation or direct access from other electric service providers. Including direct access, the SCE industrial elasticity is comparable to the elasticity used by PG&E. Price elasticity generally includes behavioral responses as well as increases in distributed generation and conservation investment. The modest elasticity adjustments used in this forecast are considered appropriate, considering that separate adjustments are made in the forecast for conservation, distributed generation and crisis behavioral response.

[13] Response to Questions 6 and 9 email from Akbar Jazayeri, SCE, to Navigant Consulting, Inc. sent on 3/29/01.
[14] From spreadsheet PG&E 5-04-01 Forecast.xls provided by PG&E.

Energy Crises Conservation Adjustment

Loads were reduced by 4 percent in 2001 and 2002 to reflect the response of Customers to the energy crisis in California and public appeals to reduce use (e.g., the Flex Your Power campaign). The California Energy Commission ("CEC") reported that compared to the same month in 2000, weather-adjusted loads decreased by 2.6 percent, 4.5 percent, 6.2 percent, 4.1 percent, and 8.9 percent in the first five months of 2001 (before the three cent rate increase and the 20/20 program started).[15]

Adjustments for Distributed Generation

In March 2001, the Commission announced a major five-year incentive program to encourage installation of efficient and/or renewable generation technologies with a capacity of one MW or less. The incentives range from 30 percent of the systems' cost, up to a maximum of $1,000 per kW for micro-turbines and for internal combustion engines utilizing waste heat recovery, and up to a maximum of $4,500 per kW for photovoltaics, wind turbines, and fuel cells operating on renewable fuels. The State has committed approximately $100 million per year in incentives through 2005. The incentives are expected to produce approximately 150 MW of incremental self-generation capacity additions per year.

As a result of improvements in technology, increased customer concerns about reliability, higher electricity prices, and the significant incentives that the State is providing, installed self-generation capacity is estimated to increase. The self-generation forecast through 2002 consists of approximately 20 MW per month of additional self-generation capacity (193 MW in 2001 and 274 MW in 2002). This estimate was developed based on discussions with equipment suppliers and local contractors regarding their current customer commitments and prospects. These estimates are consistent with the approximately 100 MW of interconnection applications for self-generation capacity that SCE has recently experienced (SCE represents approximately 46 percent of the total retail load of the IOUs).

New Programmatic Conservation

With the onset of electricity shortages and the subsequent rise in prices, a number of new conservation initiatives were undertaken, including new rate designs, funding of new initiatives, and Executive Orders. In particular AB 970, SB 5X, and AB 29X provided substantial funding for new energy conservation efforts. The peak MW effects of the programs funded from these three statutes upon summer peak (August) were estimated to be as shown in Table II-3 below:

[15] CEC table "Total Conservation in the ISO Area," 8/21/01 as posted on its website.

TABLE II-3 AVERAGE MW LOAD REDUCTIONS FROM NEW CONSERVATION		
	August 2001	**August 2002**
AB 970[1]	200	200
SB 5X[2]	60	232
AB 29x	90	90

[1] From CEC report "AB 970 Load Reduction Program Solicitation Awards– Summary of Grant Program Activity," dated March 7, 2001.

[2] Review of the final bills as signed by Governor Davis shows that SB 5X provides an incremental $387 million for conservation hardware and AB 29X provided an incremental $125 million for conservation hardware. Monies for public education and meters were excluded because the effects from those funds would be included in the "crisis conservation" and elasticity adjustments. The MW impact from these funds was estimated by assuming that 0.72 average MW of conservation would be obtained for every million dollars spent. This ratio is based on the average MW of conservation per million dollars spent from the Public Goods DSM programs in 1998 and 1999 as reported in "Annual Report on 1999 Energy Efficiency Programs and Activities," prepared by the California Board for Energy Efficiency, March, 2000. For the two years reported, 274 MW of conservation was achieved at a cost of $374 million for a ratio of 0.74 average MW per million dollars invested. A slightly lower ratio (0.72) was used in the forecast, because some of the most cost-effective programs opportunities may already be included in the 2001 Public Goods Charge DSM programs (funded at $259 million) and the AB 970 initiatives.

APPENDIX III

Short-Term Load Resource Balance

The high prices for energy in the first half of 2001 were significantly influenced by the lack of adequate supply to meet electric utility customer demand. As described in Section C, the Department's power supply contracts and associated creditworthiness has provided substantially reduced and stabilized market prices. Maintaining this recently increased capacity and price stability continues to be important in 2002. Depending upon load growth, energy conservation by retail utility customers, and the performance of existing generating plants next summer, California could continue to have less supply than desired to maintain stable spot market prices. The Department's contracts to assure delivery of power are expected to continue to play an important role in maintaining system reliability and stabilizing prices in 2002.

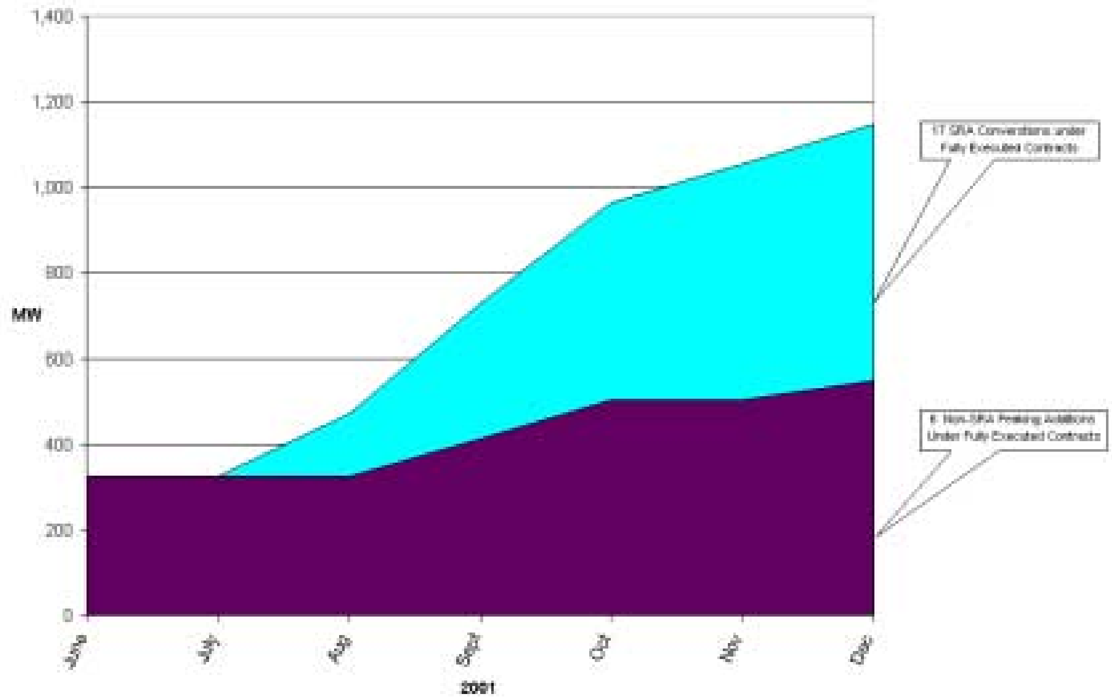
Table III-1 below presents the short-term load and energy forecast for the state of California for the summer of 2002. The prospective load and resource balance for summer 2002 is an important general indicator of the potential for volatility in the spot energy market in California. This load and resource balance is based upon the peak load forecast used to develop the net short energy projection used in the Department's revenue requirement update. However, in order to forecast the potential resources available to the Department to supply the net short, the Department must estimate the total load and resource balance of the State, including the needs and power supplies of all utilities, including in-state municipal utilities. Therefore, the total municipal utility loads and resources are also included in this table.

TABLE III-1
SHORT-TERM LOADS AND RESOURCES BALANCE, SUMMER 2002
(MW)

	June	July	August	September
State-Wide Peak Loads				
IOU – Before Adjustments	41,136	43,279	42,484	39,530
Municipal / Public Power	14,783	14,619	16,042	15,152
Direct Access	--	--	--	--
Distributed Generation	(303)	(312)	(314)	(318)
Elasticity Related Demand Reductions	(1,220)	(1,278)	(1,253)	(1,157)
Energy Crisis Conservation	(1,627)	(1,705)	(1,670)	(1,543)
AB 970 & New Programmatic Conservation	(948)	(930)	(894)	(873)
20/20 and Load Management	--	--	--	--
IOU Load Management	(1,364)	(1,392)	(1,560)	(1,739)
Subtotal Conservation & Other Load Reductions	(5,462)	(5,617)	(5,691)	(5,630)
Total State-Wide Peak Loads	50,458	52,281	52,835	49,053
State-Wide Resource Capability				
IOU-Owned Generation	10,575	10,575	10,575	10,575
IOU Derating Based on Hydro Conditions	--	--	--	--
IOU Bilateral Contracts (Out of State)	1,163	1,163	1,163	1,163
Qualifying Facilities	7,325	7,325	7,325	7,325
Non-Utility Generation (Divested Units)	16,778	16,778	16,778	16,778
Municipal / Public Power	16,810	16,810	16,810	16,810
Municipal Public Power Hydro Derating	--	--	--	--
New California Resources	4,454	6,264	6,484	7,438
Department Contracts (Out of State)	250	250	250	250
Total Peak Capability	57,355	59,164	59,385	60,339
Total Nameplate Rating (For Reference)	64,182	66,143	66,368	67,428
Gross State-Wide Reserve Margin:				
Capacity	6,897	6,883	6,550	11,286
Percent	14	13	12	23
Allowance for Forced & Scheduled Outages				
IOU-Owned Generation	(529)	(529)	(529)	(529)
Qualifying Facilities	(733)	(733)	(733)	(733)
Non-Utility Generation (Divested Units)	(839)	(839)	(839)	(839)
Municipal / Public Power	(925)	(925)	(925)	(925)
New California Resources	(223)	(313)	(324)	(272)
Total Allowance for Outages	(3,247)	(3,338)	(3,349)	(3,397)
Net State-Wide Resource Capability	54,107	55,826	56,036	56,942
Net State Reserve Margin	3,650	3,545	3,201	7,889
Capacity	7	7	6	16
Percent				

The load and resource balance for 2002 benefited materially from the Department's focus on contracts for peaking power supplies which would come on in 2001 to not only meet 2001 loads, but to increase the peak power supply for summer of 2002. As shown in Figure III-1, over 1,150 MW of new peaking resources were added to the power supplies in California based upon the assurance provided by the Department's contracts.

FIGURE III-1
CUMULATIVE MONTHLY ADDITIONS OF PEAKING CAPACITY



For purposes of Table III-1, imports into California are considered only to the extent they are either out-of-state generation owned by the IOUs as part of their utility retained generation, out-of-state generation owned by the municipal utilities, or existing bilateral contracts with out-of-state suppliers.

The load and resource balance in Table III-1 indicates a capacity reserve which is substantially below the desired 15 percent planning reserve level until September 2002. This load and resource balance could be affected favorably by additional conservation or load management (such as funded voluntary load curtailment programs) which could be implemented by the IOUs or by the Consumer Power and Conservation Financing Authority. The load and resource balance also excludes potential new long-term import contracts or short-term import purchases which could be made within the transmission constraints and available power supplies in the rest of the WSCC. The balance could be negatively affected if planned and forced outages are cumulatively higher than the allowance of approximately 3,500 MW assumed in Table III-1. In the summer of 2001, total outages varied from approximately 2,500 MW to over 7,000 MW at different times. The outage levels in this balance assumes approximately 10 percent average of total rated capacity outages for QF generation and 5 percent for all other generation. To the extent actual outages exceed these levels on a day-to-day and hour-to-hour basis, the actual capacity reserve margins in the state will vary from what is shown in Table III-1.

If the load and resource balance for the summer of 2002 is at or near the net projected level shown in Table III-1, absent a significant level of power supply in the on-peak periods under contract at known prices, there would be significant upward pressure on spot prices in 2002.

APPENDIX IV

Department Contracts

Table IV-1 below provides information on the summer 2002 on-peak hour capacity of the Department's contracts in place to supply the Customers' net short energy requirements.

TABLE IV-1
NET SHORT CONTRACTS

Counter-Party	Project Type	July 2002 Capacity (MW)
Santa Cruz County	Approx. 7x24 (as available landfill gas project)	3.0
Wellhead Power, LLC (Gates Project)	Dispatchable during 6x16 hours, for up to 4,000 hours per calendar year	41.3
Wellhead Power, LLC (Panoche Project)	Dispatchable during 6x16 hours, for up to 4000 hours per calendar year	49.9
Turlock Irrigation District (1)	7x24	25.0
City of Lodi (1)	6x16	15.0
Fresno Cogeneration Partners (Wellhead)	Dispatchable during 5x16 hours, for up to 4000 hours per calendar year	21.3
Whitewater Energy Corp. (Cabazon Project)	As-Available (wind)	43.0
Whitewater Energy Corp. (Whitewater Hill Project)	As-Available (wind)	65.0
PacifiCorp	7X24	200.0
Sunrise Power Company, LLC	Dispatchable during any hour, up to the following limits: 1734 hours (2002)	325.0
Clearwood Electric Company, LLC	Approx. 7X24	25.0
CalPeak Power--Midway LLC	Dispatchable for: up to 1200 hours during 6x16 hours in Jun-Oct and Dec-Feb: up to 1300 hours during 6x16 hours in Mar-May, Nov	48.0
CalPeak Power--Panoche LLC	Dispatchable for: up to 1200 hours during 6x16 hours in Jun-Oct and Dec-Feb: up to 1300 hours during 6x16 hours in Mar-May, Nov	48.0
CalPeak Power--Vaca Dixon LLC	Dispatchable for: up to 1200 hours during 6x16 hours in Jun-Oct and Dec-Feb: up to 1300 hours during 6x16 hours in Mar-May, Nov	48.0
CalPeak Power--El Cajon LLC	Dispatchable for: up to 1200 hours during 6x16 hours in Jun-Oct and Dec-Feb: up to 1300 hours during 6x16 hours in Mar-May, Nov	48.0
CalPeak Power--Border LLC	Dispatchable for: up to 1200 hours during 6x16 hours in Jun-Oct and Dec-Feb: up to 1300 hours during 6x16 hours in Mar-May, Nov	48.0
CalPeak Power--Enterprise LLC	Dispatchable for: up to 1200 hours during 6x16 hours in Jun-Oct and Dec-Feb: up to 1300 hours during 6x16 hours in Mar-May, Nov	48.0
CalPeak Power—Mission LLC	Dispatchable for: up to 1200 hours during 6x16 hours in Jun-Oct and Dec-Feb: up to 1300 hours during 6x16 hours in Mar-May, Nov	48.0
Calpine Energy Services, L.P. (No. San Jose Project)	Dispatchable for up to 4000 hours / year during 6x16 hours all year	180.0

PG&E Energy Trading	As-Available (wind)	66.6
Coral Power, LLC	7x24	100.0

TABLE IV-1
NET SHORT CONTRACTS (CONTD.)

Counter-Party	Project Type	July 2002 Capacity (MW)
Coral Power, LLC	6X16	300.0
Mirant Americas Energy Marketing LP	6X16	500.0
GWF Energy LLC	Dispatchable for up to 4000 hours / year during any hour	88.0
GWF Energy LLC	Dispatchable for up to 4000 hours / year during any hour	164.0
Capitol Power, Inc.	Approx. 7x24	15.0
Sempra Energy Resources	7X24	150.0
Sempra Energy Resources	6X16	300.0
Soledad Energy LLC	Approx. 7X24	13.0
Alliance Colton LLC	Dispatchable for up to 1000 hours / year during hours 0800 through 0000 hours of Jun through Oct, plus an extra 3000 hours during calendar 2002	80.0
Allegheny Energy Supply Company, LLC	7X24	250.0
Imperial Valley Resource Recovery Company, LLC	7X24	16.0
Constellation Power Source, Inc.	6x16	200.0
Dynegy Power Marketing, Inc.	7x16 for minimum requirement (daily option for another 1000MW)	500.0
Dynegy Power Marketing, Inc.	7X24	200.0
Dynegy Power Marketing, Inc.	6X16	600.0
Calpine Energy Services, L.P. (Peaking Capacity)	Dispatchable for up to 2000 hours / year during 6x16 hours in Jun - Oct, Dec, Jan	450.0
Calpine Energy Services, L.P. (Long Term Commodity Sale)	7X24	1,000.0
Williams Energy Marketing & Trading	7X24	40.0
Williams Energy Marketing & Trading	6X16	200.0
Williams Energy Marketing & Trading	6X16	160.0
Morgan Stanley Capital Group	7X24	50.0
El Paso Merchant Energy	6X16	50.0
El Paso Merchant Energy	6X16	50.0
Calpine Energy Services, L.P. (Firm)	7X24	350.0
Subtotal: August 7, 2001 Filing (MW):		7,066.6
Subtotal: Current Filing (MW)		7,222.1
Net Difference Between Revenue Requirement Filings (MW):		155.5

(1) Definitive letters of agreement for new power plant capacity additions have been approved by the Department and the counter-party. Final contracts are nearing completion.

Table IV-1 also compares the summer of 2002 capacity of the Department's contracts in place as of the August 7, 2001 filing and the contracts that are in place as of this filing. The net difference in the volumes covered under the two contract portfolios is approximately 156 MW.

APPENDIX V

Description of PROSYM and Market Price Forecasting Methodology

Forecasting the wholesale price of electricity for the retail customers of the IOUs requires modeling of the power generation and transmission systems of the entire WSCC territory. The WSCC territory includes all, or portions of 14 western states, British Columbia and Alberta provinces in Canada, and part of northern Mexico. Approximately 1,500 power generating facilities are modeled to estimate the amount of generation provided by each source, and the influence of these facilities on the price of power in the region and in California.

Wholesale power costs and plant dispatch levels in the western United States are driven by a multitude of factors. These include weather and related electricity demand, precipitation and related hydropower production, the supply and price of natural gas and coal, the power transfer capability of major interties, the operating cost, outages and retirement of generating plants, and the cost, fuel efficiency and timing of new generating resource additions. To characterize the fundamental drivers underlying the electricity market, computer simulations of market activity throughout the WSCC region are performed. To complete those simulations, the PROSYM™ price forecasting and market simulation tool[16] was used.

PROSYM

PROSYM is a widely accepted tool for simulating detailed power market activity and has a large market presence in the industry. According to its vendor, 80 percent of the major utilities in North America, and many utilities in Europe, Asia, and Australia license PROSYM. It has been used to provide analytical support and to forecast market prices and revenues in a large number of financing transactions for merchant power plants, and has gained strong acceptance in the financial community.

PROSYM is a detailed chronological model that simulates hourly operation of WSCC generation and transmission resources. Within its simulation framework, PROSYM dispatches generating resources to match hourly electricity demand and establishes market-clearing prices based upon incremental resources used to serve load. Demand and energy forecasts used by PROSYM are developed and provided by the vendor. Annual updates of these forecasts are provided by the vendor based on data obtained from Energy Information Administration ("EIA") filings and independent analysis by the vendor. For purposes of this filing, the demand and energy forecasts embedded in the model for the Customers have been replaced with the projections, as described in Appendix II.

In its hourly dispatch, PROSYM reflects the primary engineering characteristics and physical constraints encountered in operating generation and transmission resources, on both a system-wide and individual unit basis. Within PROSYM, thermal

[16] PROSYM is a proprietary modeling tool licensed to Navigant Consulting, Inc. by Henwood Energy Systems, Inc.

generating resources are characterized according to a range of capacity output levels. Generation costs are calculated based upon heat rate, fuel cost, and other operating costs, expressed as a function of capacity output of each individual generating station known to be in the WSCC. Physical operating limits related to expected maintenance and forced outage, start-up, unit ramping, minimum up and down time, and other related characteristics are reflected in the PROSYM simulation.

Hydroelectric resources are also characterized in PROSYM according to expected output levels, including monthly forecasts of expected energy production. PROSYM schedules run-of-river hydroelectric production based upon the minimum capacity rating of the unit. The dispatch of remaining hydroelectric energy is optimized on a weekly basis by scheduling hydro production in peak demand hours when it provides the most value to the electrical system.

Within the PROSYM framework, regional market clearing prices are established based upon the incremental bid price of the last generating station needed to serve demand. For most of existing supply, bid prices are composed primarily of incremental production costs. Hourly energy revenues for each generating unit are established as the product of market clearing prices and the unit's energy production during the relevant hour. The PROSYM framework mirrors a "single-price" auction, so that each generator located within the same market area receives an identical price for its energy output, regardless of its actual bid price or production cost.

While a "single-price" market auction does not presently exist in the California market other than the limited amount of energy sold to the ISO for real-time and imbalance energy, this pricing mechanism is modeled as a proxy for the average price of the residual net short. In the long-term, under a balanced supply and demand market, the average residual net short price should approximate the market-clearing price in an "as-bid" environment. In the near-term, the use of a single-price mechanism for the residual net short is expected to produce cost estimates that are somewhat higher than would actually be expected in the marketplace and therefore represents a conservative approach to the development of these energy costs.

Within the PROSYM framework, bid prices are developed for each unit and reflect the minimum clearing price the unit is willing to accept to operate. Market clearing prices reflect the bid of the last generating resource used to meet the last increment of demand. The clearing price also includes an uplift component reflecting start-up and no-load costs of the marginal unit. Station revenues are based on these market-clearing prices within the market area in which the plant is located or assigned.

Based upon the bid price of the marginal generating station in a given hour, the market clearing price is calculated using the following general approach (stated in $ per MWh):

Market Clearing Price = Incremental Production Cost + Start Cost + No-Load Cost + Price Markup

- In the determination of each generating unit's bid price, Incremental Production Cost is calculated as each station's fuel price multiplied by the incremental heat rate, plus variable operations and maintenance cost.
- The Start Cost component incorporates fuel costs and other operating costs encountered in starting the generating unit, beyond those reflected in the heat rate and variable operating cost assumptions.
- The No-Load Cost reflects the difference between average and incremental fuel costs for generating stations that are dispatched at less than full output.
- The last term of the bid price equation includes a Price Markup factor, where bid prices may rise above variable production costs. Navigant Consulting, Inc. ("NCI") uses this factor to reflect observed market behavior where wholesale prices often rise above the underlying cost of production, particularly during times when supply/demand margins are tight. Such behavior is common in power markets, and has been particularly present in California markets during the last year.

Price markups are assigned to individual generators based upon the underlying fuel efficiency, production cost, and technology type. The specific markups are designed so that bid prices rise above the cost of production as less efficient resources are called upon for power production and as the intersection of supply and demand occurs at higher points on the supply curve. The level of price markups is determined through an iterative approach with the goal of benchmarking against recent actual wholesale prices, and against observable prices in the forward market.

Three specific bidding strategies were assigned in this study:

- *Incremental Cost Bidding*: Units assigned Incremental bidding strategies incorporate only variable operating costs into their bid prices. This bidding strategy reflects a highly competitive market structure. All baseload resources and generators with relatively low production costs are assigned this bidding strategy, which reflects the bulk of available supply resources;
- *Price Markup Bidding*: Units assigned Price Markup bidding strategies submit bids close to variable operating costs during all off-peak hours. During on-peak periods, when electricity demand is higher, these stations seek to markup price in proportion to the level of electricity demand. The price markups also vary by season, and are at higher levels during the summer and winter periods when supply/demand balances are the tightest. Intermediate-type generating resources such as older steam turbine units having relatively high production costs are assigned this bid strategy; and
- *Peak Period Bidding*: Units assigned Peak Period bidding strategies also submit close to variable operating costs during off-peak hours. Price markups are assigned to these resources during on-peak hours and seasonally. The markups for resources in this category tend to be higher than those applied under the Price Markup strategy. Resources that are assigned Peak Period bidding strategies tend to have the highest production costs, such as simple-cycle gas turbine generators and internal combustion oil-fired plants. Such

resources are called upon to produce power only a small portion of the time each year.

Table V-1 provides an overview of bid strategy assignment used in this study. As shown, bid prices are set for a majority of supply resources based on incremental production costs.

TABLE V-1
CALIFORNIA AND WSCC BID STRATEGY ASSESSMENT
(PERCENT OF SUPPLY)

	Incremental	Price Markup	Peak Period Bidding	Total
California.............	68%	28%	4%	100%
Non-California.....	80%	14%	6%	100%
Total WSCC..........	75%	20%	5%	100%

Source: Navigant Consulting, Inc.

On June 19, 2001, FERC issued an order on price mitigation throughout the WSCC. Under this order, a soft price cap is set for the entire WSCC based on the heat rate of the least efficient unit and the average natural gas price during the most recent Stage 1 Emergency ("Stage 1") warning period issued by the ISO. During a Stage 1 (or higher) warning period, the cap is equal to the energy cost resulting from the heat rate of the least efficient resource being utilized in the market and the average natural gas price in California, plus a $6.00 per MWh cost for operation and maintenance expenses. A 10 percent risk premium is added for energy sold in California. Under this formula, the effective Stage 1 cap in California, if the least efficient generator was operating at 18,000 Btu per kWh and the average price of gas was $3.25 per MMBtu, would be $64.50 per MWh. If a Stage 1 warning is not in effect, the effective cap is calculated as 85 percent of the last Stage 1 cap in effect. As an example, using a $64.50 per MWh Stage 1 cap, the non-Stage 1 cap would be $54.83 (85 percent of the Stage 1 value). The Stage 1 cap is re-set during each successive ISO Stage 1 warning with a duration of 60 minutes or longer. The most recent Stage 1 cap was set in June, resulting in a FERC cap as of October 17, 2001, equal to $101.06 per MWh based upon fuel prices and marginal unit heat rates in effect in June during the last Stage 1 alert.

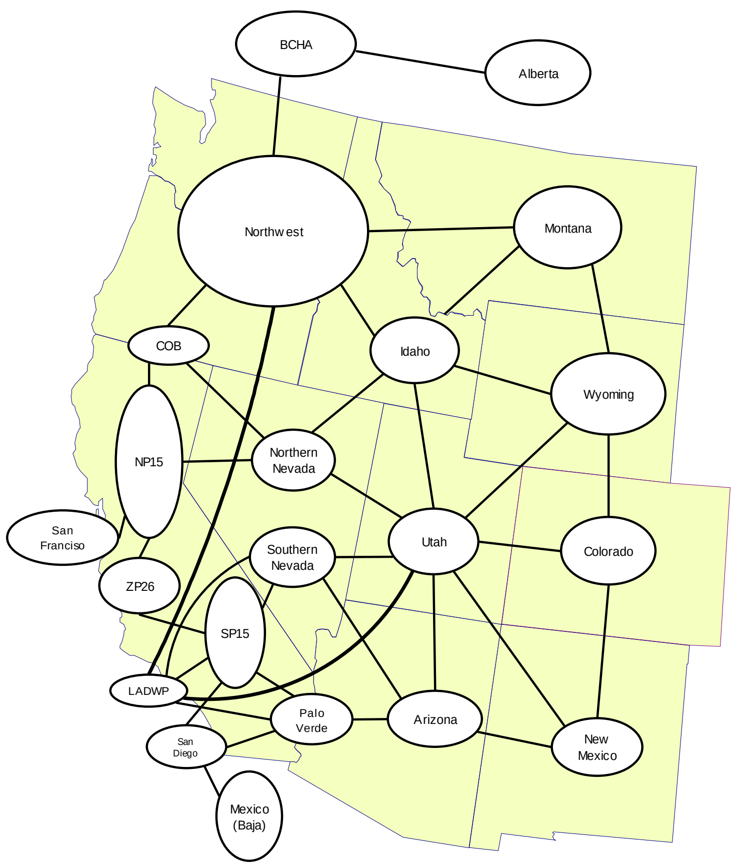
The above soft caps have been applied to the calculation of spot market prices through September 30, 2002 (the expiration of the FERC order) via the application of a weighted average price cap. The weighted average price cap is based on an expectation that Stage 1 conditions will be in effect 10 percent of the time in any given month. In months when the estimated average market clearing price exceeds the estimated ISO weighted average cap, the estimated weighted average cap price is applied to all non-long-term contract energy estimated to be purchased by the Department during that month. Under actual conditions, the Department would be expected to purchase a substantial portion of its non-contract supply outside the ISO single price market at prices below the cap. The Department is not expected to purchase non-contract energy outside the ISO market above the applicable price cap, since no market purchases (through the ISO market or otherwise) can be made above the cap unless sellers can document a cost basis above the cap. In addition, the market-clearing price in the ISO spot markets will not always match or exceed the applicable price cap in a given month but, rather, would exceed the cap only in certain days or hours within the month.

WSCC Regional Market Definitions

WSCC electricity markets sometimes experience binding transmission constraints. During times when constraints are binding, low-cost generators are forced to reduce output in favor of higher-cost units located within the constrained region. To reflect transmission constraints encountered in WSCC markets, 21 separate market regions are simulated within PROSYM, with transfer limitations between each region reflecting expected transmission system configurations.

Separate market clearing prices were established within each regional market outlined in Figure V-1. In establishing the market-clearing price for each region, the PROSYM simulation takes into account economic import and export possibilities and sets the market-clearing price as the bid price of the marginal generator needed to serve a final increment of demand within the region.

FIGURE V-1
WSCC REGIONAL MARKET DEFINITIONS



Simulation of New Resource Additions

New resource additions must be included in the simulation in order to meet increases in peak demands. A review of potential and planned new resource additions throughout the WSCC reveals that they will be built and owned primarily by independent power producers. The technology, fuel type, size, and location of these new plants will depend primarily upon wholesale power market prices. Prices available to an independent power producer must be sufficient to allow it to earn a return on equity that is consistent with similar risk capital investments.

To forecast the amount of capacity that would be added in each region of the WSCC, known potential new generating resources were reviewed to identify those currently under site certification or construction. These plants were given a high probability of completion and were added to the simulation resource base in their expected completion year. Those resources announced or under feasibility study were added to the simulation resource base only if the annual average market clearing price in their completion year was forecast to exceed that which would provide an adequate return on equity. Energy revenues (hours of operation multiplied by energy prices) must be greater than the average annual costs (fuel and capacity) of the project. Capacity costs of the particular resource to be added were estimated based on publicly available cost information for the specific type of plant, and on certain financing term, interest rate, and return on equity assumptions. Table V-2 summarizes these assumptions for combustion turbine and combined cycle combustion turbine based plants, which are expected to represent the major portion of all new generating resource additions in the WSCC during the Study Period.

TABLE V-2
GENERIC RESOURCE ASSUMPTIONS
(2000 DOLLARS)

Unit Characteristic	Combustion Turbine	Combined Cycle
Heat Rate (Btu / kWh)	11,000	7,100
Fixed O&M ($ / kW-year)	3.00	10.00
Variable O&M ($ / MWh)	4.00	2.00
Forced Outage Rate (%)	0.00	2.00
Maintenance Outage Rate (%)	4.00	4.00

Source: Navigant Consulting, Inc.

Contract resources, including the IOU bilateral contracts, power purchase agreements, and QF contracts, as well as the Department contracts, were explicitly modeled in the simulation, accounting for their respective capacities, delivery points, minimum takes and other features. “Firm” contract resources are assumed to be called upon prior to the dispatching of other available resources and therefore are modeled at their full available energy output. Finally, a broad array of other inputs and assumptions were made in performing the WSCC market simulation. These include resource availability, resource retirements, fuel prices, operation and maintenance costs, outage factors, transmission factors, and assumed market conditions.

Results of the simulation include average monthly dispatch level, fuel cost, and variable operation and maintenance costs for each generating resource modeled. Average monthly power purchase levels for QF contracts, the Department contract resources, and IOU bilateral contracts were also generated. Finally, average monthly peak and average market clearing prices for each modeled market region were generated. The operating cost of the plant dispatched to serve the last increment of load demand for a given region was considered the market-clearing price for that region.

Ancillary Services Price Forecast Methodology

The IOUs will incur ancillary service charges from the ISO for scheduling their designated load. The volume of ancillary services required in any given hour is based on the total load scheduled by the IOU for that hour. The price for ancillary services is based on prices that result from the day-ahead and hour-ahead bids for such services that the ISO receives from its ancillary services auction process.

A strong correlation exists between energy prices and ancillary services prices. Based on hourly historical price data for the period from April 1998 through December 2000, a regression analysis was performed resulting in an econometric model of ancillary service price (spinning reserves were used as a proxy for ancillary services) as a function of several variables. The primary independent variable driving the price of ancillary services is energy price.

To develop the price forecast, the energy market clearing price forecast and the system load were analyzed using the econometric model. Simulations were then conducted to calculate the forecasts of prices as well as the distributions and confidence intervals of the prices. The volume of ancillary services needed by each IOU was developed assuming that the ISO would require, on average across all services, an amount equal to 3.7 percent of the total energy requirements of the IOUs after consideration of the amount of ancillary services self-provided by the IOU from URG. The Department is assumed to be responsible for ancillary services equal to 3.7 percent of the volume of the total power requirements of the Customers times the market clearing price for energy, constrained by the FERC price cap.

Market Clearing Prices and Ancillary Services Prices

Electricity prices reached high levels and exhibited significant volatility early in the first half of 2001. Upon the Department entering into several long-term contracts, and the reduction in net short energy requirements due to increased conservation this summer, market clearing prices have dropped. This pattern is consistent with the tight supply and demand balances currently being experienced in the western markets, along with high natural gas prices. Ancillary services prices are also expected to trend downward over the next few years as the underlying energy prices decline. Appendix VI provides information on the development of estimated natural gas prices for the Revenue Requirement Period.

Residual Net Short Purchases

A load and resource table (capacity and energy) was constructed for each of the IOUs to forecast the amount of resources needed after the IOU utility retained generation, new conservation and load management programs, and the Department contracts were considered. Prior to January 1, 2003, residual net short purchases will be made by the Department. After this date, consistent with current law, the IOUs or a creditworthy governmental entity other than the Department is expected to be responsible for these purchases. Table 6 in Section D of this filing provides a summary of estimated quarterly residual net short costs, along with estimated Department contract costs, through 2002. The FERC price caps are reflected in the estimated residual net short costs shown in Table 6 through September 2002.

APPENDIX VI

Discussion of Natural Gas Pricing Assumptions and Forecasting Methodology

Natural gas prices are an input in estimating power prices and the costs the Department can expect to incur in meeting the Customer's net short requirements. This appendix describes recent events in the natural gas market and how the natural gas prices used to model power prices for this revenue requirements filing were developed.

Natural gas prices in the United States demonstrated a relatively stable pattern from 1996 through mid-2000, fluctuating between $2.00 and $3.00 per MMBtu. Gas prices began their current increase in mid-2000, when summer prices did not decline as expected. This price increase has been attributed to several factors, including (i) a decline in drilling activity in 1998 and early 1999; (ii) a warm summer, resulting in higher electric demand for gas-fired generation; and (iii) a return to more normal winter weather conditions across much of the country during the 2000–2001 winter season compared to the several previous winters. As reported by the EIA, demand for natural gas across the country increased by 1.1 trillion cubic feet ("Tcf") in calendar year 2000, over the average for the previous three years (21,641 Tcf per year). Production in the United States during 2000, however, only increased by 0.6 Tcf over the 1999 production level (18,623 Tcf) (the difference between total demand and production is made up from imports). Additionally, the general expectation that gas prices would drop during the summer of 2000 led many in the industry to delay purchases of natural gas for underground storage. By August and September 2000, the realization that prices would not decline left storage users with little choice but to acquire needed gas for storage during late summer and early autumn, thereby exerting additional pressure on supplies and price levels.

Historically, prices in California reflected the broader market dynamics described above, amplified or dampened by local factors. Prior to 1997, Topock frequently traded at a discount to Henry Hub, owing largely to a perceived excess of interstate pipeline capacity relative to statewide demand. From 1997 through 1999, prices at Topock, Arizona (where interstate pipelines from the U.S. Southwest interconnect with PG&E and Southern California Gas Company ("SoCalGas")), generally paralleled prices at Henry Hub, plus or minus a small basis differential that varied month-to-month. The basis differential ("basis" is defined as the Topock price minus the Henry Hub price), as measured using Monthly Contract Index prices established during bid week and reported in Gas Daily, during the 1997 through 1999 period ranged from $(0.09) per MMBtu to $0.12 per MMBtu. In 2000, the basis began to rise, climbing from $0.04 per MMBtu in June 2000 to $8.42 per MMBtu by December 2001. The basis remained at this high level, reaching $10.11 per MMBtu by May 2001, before dropping to $7.98 one month later in June. When the hot summer weather expected by the market did not materialize in June 2001, basis values on weekends dropped close to zero. July 2001 bid week set the basis to California at $1.64 per MMbtu. Continued cooler than expected conditions dropped the August 2001 basis further, to

$0.57 per MMBtu; by September 2001 the lack of weather-induced demand combined with widespread reports that storage would likely be full for the coming winter led the basis to fall to $0.31 per MMBtu.

A number of factors likely contributed to the basis run-up and subsequent decline. As suggested above, one would certainly be the balance of demand for natural gas in California relative to pipeline delivery capability into the state. Another would be the late August 2000 explosion on the El Paso Natural Gas ("El Paso") system at Carlsbad, New Mexico that reduced by approximately one-third El Paso's ability to deliver natural gas to California. While other pipelines were able to increase deliveries and replace some of the El Paso capacity, the reduced deliveries left less gas available to inject into storage in southern California. Yet another factor would be the below normal precipitation in California and the Pacific Northwest during the 2000–2001 winter season. Below normal precipitation helped keep prices high as market participants factored in their expectation of higher summer prices on the belief that the dry hydrological conditions would keep California pipelines and local distribution systems near maximum capacity. Higher demand due to dry hydrological conditions on top of what PG&E and SoCalGas reported as very high throughput during calendar year 2000 created expectations that calendar year 2001 would present very little excess capacity and allow sellers to command high prices. While neither the Department nor its energy consultant has investigated such claims, there have also been claims by parties (including the Commission and SCE) that El Paso Natural Gas and its affiliate El Paso Merchant Energy exercised market power so as to drive up the price of natural gas at the California border. FERC has before it now a draft decision that appears to conclude that El Paso may have had market power but did not exercise it to keep prices high.

The decline in prices and basis differential to California during 2001 can be understood as the reversal of most of these factors. EIA's October Short-Term Outlook estimates that 2001 production will be 0.7 Tcf higher than in 2000, and that demand will be approximately 0.5 Tcf lower. Storage, across the country and western United States, is estimated to finish the injection season at 3.1 Tcf, 10 percent more than the average over the last six years. The lack of demand-inducing weather conditions and a slowing economy mean that there is currently insufficient demand for natural gas to keep prices at the high levels experienced over the last year.

Forecasting Methodology

Estimated natural gas prices have been developed using a proprietary forecasting model developed by Navigant Consulting, Inc., the Department's energy consultant. The model uses linear regression on 30 years of annual data to estimate a general relationship between annual natural gas prices and several independent variables: prior period prices, a weather variable capturing annual heating degree days, and a variable representing gas well drilling activity. The resulting econometric equation is used to project future annual prices at Henry Hub. The econometric results exhibit strong and reasonable properties in terms of statistical measurements such as standard error and R-squared and, when data inputs are used that reflect historical conditions, the model produces price estimates that are very close to those actually experienced. In order to produce the forecast values, the model assumes average weather and the level of drilling activity projected by EIA as being necessary to meet a 31 Tcf market with continued technological improvements. Monthly prices are calculated using historical factors to "spread" the annual prices into a monthly pattern.

California border prices are then calculated by adding a basis differential to the Henry Hub price. The Base Case used in this revenue requirement update initially sets the basis at $0.50 per MMBtu – close to the maximum rates for firm transportation approved by the FERC. From this level, small seasonal variations in the basis are allowed, resulting in a drop in the differential during summer months when demand is presumably lower. The High Basis Case, in contrast, assumes that high demand relative to delivery capability or other factors drives the basis higher. The High Basis Case value was set at three times the monthly basis differentials assumed in the Base Case. The Low Basis Case sets the basis at $0.00 per MMBtu throughout the forecast period. This range of basis values was selected in order to capture a range of values consistent with observed and expected market conditions.

This forecasting model has also been used to project fuel prices delivered to the other local markets across the WSCC in order to model power prices in those markets. These fuel prices were developed using observed differentials between those markets and Henry Hub. In addition, it was assumed that a generator would likely connect directly to an interstate pipeline. This means that generators will pay for interstate transportation from the basin to their delivery point, but allows them to avoid charges to transport gas over a local distribution system. Table VI-1 contains the resulting average annual prices for each region. The prices shown are stated in nominal dollars, assuming inflation of 2.5 percent per year.

TABLE VI-1
AVERAGE ANNUAL REGIONAL GAS PRICES
($/MBTU)

	Topock	Malin	Citygate	PacNW	Rockies	AZ_NV
Q4 2001	3.63	3.08	3.58	2.97	2.88	2.84
2002	3.64	3.10	3.60	3.04	2.95	2.90

APPENDIX VII

Conservation and Demand Side Management Programs in California

With the onset of electricity shortages and the subsequent rise in prices, a number of new conservation initiatives have been undertaken in California, including new rate designs, funding of new initiatives, and Executive Orders during 2001. Some of these programs are complementary and some initiatives target the same end-use or savings. For example, a program funding the installation of time-of-use ("TOU") meters supports the implementation of expanded TOU, price responsive, and load management programs. Consequently, the net effect of all of the initiatives is less than the sum of the impacts of the individual initiatives. The initiatives include the following:

- AB 970, signed into law in September 2000, provided funding for conservation designed to reduce peak electricity usage and directed the Commission and utilities to provide incentives for demand responsive systems and distributed generation. AB 970 provided $50 million for conservation and peak demand reduction programs. Funding was provided for 135 projects, with an estimated peak load reduction of 335 MW. Approximately 103 MW of this total load reduction results from load management programs. The Commission also directed the IOUs to develop three small-scale, demand-responsive pilot programs and provide approximately $125 million per year in incentives for customer-installed self-generation resources. Funding for these programs is provided by the State;
- AB 29X and SB 5X, passed in April 2001, provided an aggregate funding of $500 million for conservation and peak demand reduction. AB 29X and SB 5X also provided funds to (i) assist low-income households in meeting the higher costs of electricity; (ii) foster conservation education; and (iii) foster public awareness of renewable and clean self-generation. The CEC estimates that this funding will produce 2,691 MW of peak load reduction by September 2001, including approximately 500 MW from installation of TOU meters and 1,000 MW from a public appeals campaign to conserve. These programs are funded from the State's General Fund;
- The "20/20 Program," established by Executive Order of the Governor on March 13, 2001, provided Customers with rebates equal to 20 percent of their bills if they reduced consumption by more than 20 percent relative to their consumption for the same period in the previous year. For non-residential customers on TOU rates, this 20 percent reduction was required to be obtained during the on-peak period. The program applies to the four summer months from June through September during 2001. The State estimates the program impacts were 3,100 MW of peak demand savings and 3,500 GWh of energy savings annually. The program costs to the Department were approximately $350 million. The Department funded the 20/20 program for 2001, but no funding of this program is included in the Department's revenue requirement for 2002.

- Government conservation and peak load reduction initiatives include the following: (i) a voluntary 7 percent reduction in energy usage in local and federal government operations; (ii) approximately $50 million to fund initiatives to reduce energy consumption and peak demand by state government operations (this is in addition to projects funded through AB 970); and (iii) a voluntary reduction in state agency and State Water Project operations. The state initiatives are reported to be reducing average energy usage by 8 percent from comparable 2000 levels and are expected to produce a 20 percent reduction in prior year usage levels during Stage 2 and Stage 3 alerts. The CEC estimates that the total impact of these initiatives will be a reduction of 658 MW on peak, of which 300 MW is water pumping load management by the Department for the State Water Project. The costs associated with the reduction in pumping load have been funded through the Department's State Water Project operations.
- Revised rate designs to encourage conservation that include tiered residential rates (higher rates for households that use more electricity) and expanded TOU rates with higher peak period charges. The rate design revisions are expected to result in some reduction in energy use due to price elasticity. The tiered structure and expansion of TOU rates will augment the expected price elasticity effect;
- Expansion of utility interruptible and load control programs. In April 2001, the Commission issued an order directing a continuation and expansion of IOU interruptible and load control programs. Several new programs were developed to appeal to a broader range of Customers and to address a range of issues associated with the operation of the interruptible programs. Three new interruptible programs were developed, including:
  - Voluntary Demand Response Program pays Customers that voluntarily reduce loads when requested an amount equal to $350 per MWh of load reduction. This program was rolled into the Demand Bidding Program discussed below;
  - Optional Binding Mandatory Curtailment exempts Customers from rolling blackouts if total loads on their distribution circuit decrease by a certain amount for the entire duration of every outage; and
  - New Base Interruptible Program Customers must reduce their usage for up to 120 hours per year in exchange for a monthly bill credit.
- The ISO Demand Relief Program provides an $80,000 per MW reservation fee for the four summer months of 2001 and 2002, plus $500 per MWh for load interruptions. Approximately 1,135 MW of interruptible load bids were received from two requests for bids ("RFB"). Contracts were not executed with most of the bidders, and the program was not implemented for the summer of 2001.
- The ISO Discretionary Load Control Program, similar to the IOUs' Voluntary Demand Response Program, allows Customers to voluntarily sell load reductions during periods when the ISO anticipates needed load relief. The RFB associated with this program was released in mid-April and

approximately 35 MW of load signed up for this program. The ISO is re-evaluating the design of this program. In mid-July 2001, this program was to be rolled into the new Demand Bidding Program, but it was not implemented for the summer of 2001.

- In June 2001, the IOUs, the Commission, the ISO, the Department, and the Governor's office developed a Demand Bidding Program. Customers were able to post the amount of load that they would be willing to curtail at different price levels. The Department would select which bids to accept based on the prices bid. Although customers enrolled approximately 400 MW in this program, no curtailments were called for, and the Department did not incur any costs for this program in 2001.
- A number of smaller programs including pilot demand responsive programs, expansion of existing air conditioning cycling programs, and programs targeted at specific niches were also being pursued, but were not implemented in 2001.
- As of mid-September 2001, the utilities had a total of 1,739 MW enrolled in these load management programs. The programs were never called upon during the summer of 2001.